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A black and white photograph of an oil drilling rig. Two workers wearing hard hats and safety gear are visible. One worker is in the center, leaning over a large circular component of the rig. Another worker is in the lower right, also working. The scene is filled with various mechanical parts, cables, and structural elements of the drilling equipment.

For 2007 the Company will invest approximately \$120 million in exploration and development activities and plans to drill, similar to last year, approximately 45 net wells primarily in the Foothills. ProEx will continue to concentrate on its traditional Foothills targeted Halfway reservoirs and in addition will build upon the Cretaceous success with further Bluesky and Gething drilling planned at Julienne, Altares, Bernadette, Gundy and West Beg.

ProEx Energy Ltd. 2006 Financial Information

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

ProEx Energy Ltd.

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The following discussion and analysis as provided by the Management of ProEx Energy Ltd. ("ProEx" or "Company") as of February 26, 2007, is to be read in conjunction with the accompanying audited financial statements and related notes for the years ended December 31, 2006 and 2005. The financial data presented has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar.

Description of Company – ProEx Energy Ltd. is a Calgary based, natural gas focused, exploration and development company, established on July 2, 2004. Primary operating areas include the northeast British Columbia Foothills and Fort St. John Plains regions. Common shares of ProEx trade on the Toronto Stock Exchange ("TSX") under the symbol PXE.

Non-GAAP Measures – The MD&A contains the term "funds generated from operations" and "netbacks" which are non-GAAP terms. The Company uses these measures to help evaluate its performance. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. Management uses funds generated from operations to analyze operating performance and leverage and considers funds generated from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds generated from operations should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with Canadian GAAP as an indicator of the Company's performance. Therefore references to funds generated from operations or funds generated from operations per share (basic and diluted) may not be comparable with the calculation of similar measures for other entities. The reconciliation between net earnings, funds generated from operations and cash flow from operations can be found in the statements of cash flows in the year end audited financial statements. Funds generated from operations per share is calculated using the basic and diluted weighted average number of shares for the period.

Management uses certain industry benchmarks such as operating netback and net asset value to analyze financial and operating performance. These benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

Boe Presentation – Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet ("mcf") to one barrel ("bbl") is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived by converting natural gas to oil in the ratio of six mcf of gas to one barrel of oil.

Forward-Looking Information – Certain information regarding the Company set forth in this document, including Management's assessment of the Company's future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing, and transportation such as loss of market, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources; as a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

2006 HIGHLIGHTS AND SELECTED FINANCIAL INFORMATION

<i>(\$ thousands, except per share amounts)</i>	2006	2005
Production		
- Natural gas (mcf/d)	28,836	16,864
- Crude oil (bbls/d)	335	274
- Natural gas liquids (bbls/d)	144	77
- Total production (boe/d)	5,285	3,162
Pricing		
- Natural gas (\$/mcf)	7.08	9.70
- Crude oil (\$/bbl)	69.26	66.49
- Natural gas liquids (\$/bbl)	67.03	62.32
Petroleum and natural gas revenue (including hedging settlements)	86,527	68,086
Funds generated from operations	43,531	36,044
- Basic per share	1.23	1.17
- Diluted per share	1.04	0.96
Net earnings	15,163	15,015
- Basic per share	0.43	0.49
- Diluted per share	0.36	0.40
Capital expenditures	152,161	85,454
Total assets	290,307	150,193
Bank debt and working capital deficiency	27,838	9,275

Operations

- Average 2006 production was 5,285 boe per day compared to 3,162 boe per day during the same period in 2005, an increase of 67 percent while production per diluted share increased 50 percent during the same period.
- 2006 fourth quarter production averaged 6,080 boe per day compared to 4,561 boe per day in the fourth quarter of 2005, an increase of 33 percent while production per diluted share increased 22 percent during the same period.
- Natural gas production was 33,505 mcf per day during the fourth quarter of 2006 compared to 28,348 mcf per day during the prior quarter and 24,942 mcf per day in the fourth quarter of 2004.
- Crude oil and natural gas liquids production averaged 496 bbls per day during the fourth quarter of 2006 compared to 479 bbls per day in the prior quarter and 404 bbls per day in the fourth quarter of 2005.
- Drilled 63 gross wells (44.0 net) during the year with a 96 net percent success rate, resulting in 57 natural gas wells (41.0 net) and 3 oil wells (1.3 net).
- During the year, the Company increased net undeveloped land to 271,411 net acres from 160,869 net acres at December 31, 2005. At December 31, 2006 undeveloped lands under the control of ProEx, including option acreage, is approximately 285,296 acres.

Reserves

- Proved reserves at December 31, 2006 were 21.7 million boe compared to 11.8 million boe at December 31, 2005, an increase of 84 percent while reserves per diluted share increased 65 percent during the same period.
- Proved plus probable reserves at December 31, 2006 were 31.5 million boe compared to 15.0 million boe at December 31, 2005, an increase of 110 percent while proved plus probable reserves per diluted share increased 88 percent during the same period.
- Production replacement on a proved reserve basis was 6.1 times and on a proved plus probable reserve basis was 9.5 times.
- The average proved plus probable reserve additions per well during 2006 was approximately 2.6 bcf of natural gas.

Capital Efficiency

- Finding, development and net acquisition costs ("FD&A") related to the total 2006 capital program (including the change in future development capital) were \$15.70 per boe proved and \$10.93 per boe proved plus probable. This translates into a recycle ratio of 1.6 times on a proved basis and 2.2 times on a proved plus probable basis. Excluding changes in future development capital, FD&A costs were \$12.87 per boe proved and \$8.26 per boe proved plus probable.
- All-in 2006 production replacement cost was \$29,124 per boe per day.

Financial

- Petroleum and natural gas revenue (including hedging settlements) increased 27 percent to \$86.5 million for the year compared to \$68.1 million during the prior year.
- Average natural gas prices for 2006 were \$7.08 per mcf compared to \$9.70 per mcf in 2005, a decrease of 27 percent.
- Funds generated from operations increased 21 percent to \$43.5 million (\$1.04 per diluted share) for the year compared to \$36.0 million (\$0.96 per diluted share) during the prior year while funds generated from operations per diluted share increased 9 percent during the same period.
- Net earnings for the year was \$15.2 million (\$0.36 per diluted share) consistent with \$15.0 million (\$0.40 per diluted share) recorded in the prior year.
- Capital expenditures totaled \$152.2 million during 2006 compared to \$85.5 million during 2005.
- Bank debt and working capital deficiency was \$27.8 million at December 31, 2006 compared to a \$100 million demand revolving operating credit facility available at year end.

RESULTS OF OPERATIONS

Production

The following is a summary of daily production for the quarterly and annual periods indicated:

	2006					2005				
	Annual	Q4	Q3	Q2	Q1	Annual	Q4	Q3	Q2	Q1
Natural gas (mcf/d)	28,836	33,505	28,348	29,931	23,454	16,864	24,942	17,255	12,943	12,170
Crude oil (bbls/d)	335	343	331	352	314	274	316	272	267	242
Natural gas liquids (bbls/d)	144	152	148	163	112	77	88	66	66	89
Total production (boe/d)	5,285	6,080	5,204	5,503	4,335	3,162	4,561	3,214	2,490	2,359

ProEx's production for the year ended December 31, 2006 averaged 5,285 boe per day. The production was comprised of 335 bbls per day of crude oil, 144 bbls per day of natural gas liquids and 28,836 mcf per day of natural gas. Production increased substantially over the 3,162 boe per day recorded in the prior year due to the success of the 2006 drilling and completion program.

(boe/d)	Production
Production Reconciliation	
Production fourth quarter 2005	4,561
Decline on base production	(2,189)
Exploration program production additions during 2006	5,223
Decline on new 2006 production	(1,515)
Production fourth quarter 2006	6,080

Cost of Production Additions

During 2006, the Company added 5,223 boe per day of new production from its drilling and completion program. With a capital investment program of \$152.2 million, this results in production being efficiently added at a cost of \$29,124 per boe per day. This calculation is highly sensitive to the timing of production additions in the fourth quarter, which was later than originally forecasted in 2006.

Producing Areas

The following table summarizes the Company's average production by producing areas for the year ended December 31, 2006 and the prior year.

(boe/d)	2006	2005
West Beg	2,391	924
Gundy and Town	1,384	1,216
Fort St. John Plains	729	867
Altares/Bernadet	670	143
Dogrib	111	-
Halkirk, Alberta ⁽¹⁾	-	12
Total daily production	5,285	3,162

⁽¹⁾ Disposition of the Halkirk, Alberta asset occurred in January 2005.

Commodity Pricing

<i>Average Benchmark Prices</i>	2006	2005
Natural gas – Station #2 (Cdn \$/mcf daily index)	6.28	8.62
Natural gas – AECO (Cdn \$/mcf daily index)	6.57	8.80
Natural gas – AECO (Cdn \$/mcf monthly index)	7.05	8.56
Exchange rate (US\$/Cdn\$)	1.1343	1.2114

<i>ProEx Realized Prices</i>		
Natural gas – before hedging (\$/mcf)	6.84	9.70
Hedging settlements (\$/mcf)	0.24	-
Natural gas – after hedging (\$/mcf)	7.08	9.70
Crude oil (\$/bbl)	69.26	66.49
Natural gas liquids (\$/bbl)	67.03	62.32

The year 2006 began with falling natural gas prices as a result of the record warm temperatures in January and prices remained on a downward trend through much of the first six months. Disappointingly small natural gas storage withdrawals and seasonably low natural gas demand continued to put downward pressure on prices but was partially offset by strong crude oil prices. June marked the beginning of the hurricane season but in spite of dire warnings from the forecasters, no significant storms made land-fall in 2006.

The third quarter started with a heat wave across much of the United States which resulted in record high levels of gas consumption as well as the first ever recorded withdrawal of natural gas from storage during the summer. Crude oil prices began the third quarter with West Texas Intermediate (“WTI”) averaging a record high of US\$74.46 per barrel due to supply concerns and a significant “risk premium” related to Middle East tensions. Oil prices softened through the balance of the third quarter and continued through the fourth quarter as crude oil and refined products inventories remained high and Middle East tensions eased. By year end, crude oil prices had averaged a new annual record of US\$66.22 per barrel for WTI.

For natural gas, the fourth quarter began with prices at their lowest levels in many months. Natural gas storage facilities were filled to record levels and winter weather had not begun to absorb the excess supply. However, the weather turned cold the first week of December which created several weeks of large storage withdrawals and strengthened gas prices. By mid December, the cold gave way to forecasts for above normal temperatures. In spite of the high storage volume and resulting oversupply of natural gas, prices for 2006 averaged US\$7.26 per million btu for the New York Mercantile Exchange (“NYMEX”) and Cdn\$6.17 per gigajoule (“gj”) at the Canadian Alberta Energy Company interconnect with the TransCanada Alberta system (“AECO”).

Looking toward 2007, we anticipate WTI oil prices will average within the US\$55.00 to US\$65.00 per barrel range and natural gas at AECO is expected to average between Cdn\$6.00 to Cdn\$8.00 per gj. ProEx produces predominantly light oil and high heat content liquids rich natural gas that attract premium market prices.

Natural Gas Pricing

The U.S. natural gas prices are typically referenced off NYMEX at Henry Hub, Louisiana while Alberta natural gas is referenced off the AECO Hub and British Columbia natural gas off of Sumas Washington or Station #2 market centers. Virtually all of ProEx’s natural gas is sold at pricing based at one of the Alberta or British Columbia hubs. ProEx typically sells 50 percent of its natural gas production on monthly indexes and 50 percent on daily indexes.

<i>Natural Gas Production and Prices by Province</i>	2006		2005	
	Mcf/d	\$/Mcf	Mcf/d	\$/Mcf
Alberta ⁽¹⁾	-	-	43	6.52
British Columbia	28,836	6.84	16,821	9.70
Total production and average sales price	28,836	6.84	16,864	9.70

⁽¹⁾ ProEx disposed of its Halkirk, Alberta assets in January 2005.

<i>British Columbia Natural Gas Prices</i>	2006	2005
NYMEX (US \$/mmbtu 12 month average – last 3 Days)	7.26	8.55
Less: Station #2 basis differential to Henry Hub (US \$/mmbtu)	(1.78)	(1.50)
Station #2 (US \$/mmbtu)	5.48	7.05
Average exchange rate	1.1343	1.2114
Station #2 price (Cdn \$/mcf daily index) ⁽¹⁾	6.28	8.62
Premium: ProEx realized price vs spot	0.56	1.08
ProEx average British Columbia field price (Cdn \$/mcf)	6.84	9.70

⁽¹⁾ Converted from \$/mmbtu to \$/mcf using the Energy and Utilities Board conversion factor.

Risk Management

The Company's hedging activities are conducted pursuant to the Company's Risk Management Policy approved by the Board of Directors. The Risk Management Policy has the following objectives:

- To reduce risk exposure to budgeted annual cash flow projections resulting from uncertainty or changes in commodity prices, interest rates or foreign exchange.
- To limit the permissible structures to ensure hedging effectiveness.
- To limit hedging up to a maximum of 50 percent of budgeted production before royalties.
- To limit hedging activity to counter-parties that provide sufficient collateral in support of payment or have investment grade credit ratings.

In the fourth quarter of 2006, the Company entered into financial transactions for natural gas, including monthly index swaps and call spread transactions. ProEx' commodity risk management positions are described in note 9 in the financial statements attached. As at December 31, 2006 the Company would have received \$9.1 million on the termination of these contracts.

The Company currently has natural gas financial and physical contracts in place for the following production volumes:

<i>Financial Price Risk Management</i>	<i>Contract Natural Gas Volumes ('000 gj/d)</i>
First quarter of 2007	17.0
Second quarter of 2007	20.0
Third quarter 2007	20.0
Fourth quarter 2007	6.7

Petroleum and Natural Gas Revenues

Petroleum and natural gas revenues (before hedging settlements) of \$84.0 million for 2006 was up 23 percent over the \$68.1 million in revenues recorded in the prior year. ProEx recorded \$72.0 million in natural gas sales (\$59.7 million in the prior year), \$8.5 million in crude oil sales (\$6.7 million in the prior year), and \$3.5 million in natural gas liquid sales (\$1.8 million in the prior year). Increased petroleum and natural gas revenues over the prior year are a result of natural gas and related natural gas liquids production increases partially offset with lower commodity prices as compared with the prior year. Hedging settlements during the fourth quarter of 2006 added \$2.5 million to revenues. There was no hedging activity in the prior year.

<i>(\$ thousands)</i>	2006	2005
<i>Revenues by product</i>		
Natural gas	72,007	59,676
Crude oil	8,473	6,658
Natural gas liquids	3,520	1,752
Hedging settlements	2,524	-
Total Petroleum and natural gas revenues	86,524	68,086

Royalties

Royalty rates decreased to 27.9 percent (before the impact of hedging settlements) during 2006 compared to 29.6 percent during the prior year. The lower royalty rates for 2006 as compared to 2005 is attributable to the lower natural gas prices; and an increase in provincial marginal well royalty rate incentives received on certain low volume wells in British Columbia. Management anticipates that the average royalty rates for 2007 will be between 25 and 30 percent.

<i>(\$ thousands, except where otherwise indicated)</i>	2006	2005
Crown	17,931	16,163
Freehold and overriding	5,510	3,973
Total royalty expense	23,441	20,136
Royalties (\$/boe)	12.15	17.45
Average royalty rate (after impact of hedging charges - %)	27.1	29.6
Average royalty rate (before impact of hedging charges - %)	27.9	29.6

<i>(\$ thousands, except where otherwise indicated)</i>	2006	2005
Royalties by Product		
Natural gas royalties	20,698	18,342
\$/boe	11.80	17.88
Average natural gas royalty rate (%)	28.7	30.7
Natural gas liquids royalties	885	413
\$/boe	16.85	14.69
Average natural gas liquids royalty rate (%)	25.1	23.6
Crude oil royalties	1,858	1,381
\$/boe	15.19	13.79
Average crude oil royalty rate (%)	21.9	20.7

Operating Expenses

Operating expenses for 2006 were \$9.2 million, compared to \$6.2 million in the prior year. The increase is due to higher production in 2006 compared to 2005. On a boe basis, operating expenses for 2006 decreased 11 percent to \$4.75 from \$5.34 in 2005 due to increased operating efficiencies. Management anticipates 2007 normalized operating expenses to be in the \$5.00 to \$5.25 per boe range.

<i>(\$ thousands, except where otherwise indicated)</i>	2006	2005
Operating expenses - natural gas properties	8,230	5,351
-\$/boe	4.49	5.01
Operating expenses - crude oil properties	942	813
-\$/boe	9.82	9.53
Operating expenses - all properties	9,172	6,164
-\$/boe	4.75	5.34

Transportation Expenses

Transportation expenses were \$7.0 million for 2006 compared to \$4.0 million in the prior year. On a per boe basis, transportation expenses were \$3.60 in 2006 compared to \$3.47 in 2005. The increase in transportation expense per boe as compared to the prior year is due primarily to an increase in toll rates during the year. In British Columbia, there is an infrastructure owned by Duke Energy that enables gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

Operating Netbacks by Product

Although many wells produce both crude oil and natural gas, a well is categorized as a natural gas well or an oil well based upon the higher proportion of natural gas or crude oil production. The following table summarizes the operating netbacks for natural gas, crude oil and all properties combined for the year and for the prior year.

	2006	2005
Natural gas properties (\$/mcf)		
Sales price - before hedging	6.84	9.76
Hedging settlements	0.23	-
Royalties	(2.04)	(2.98)
Transportation expenses	(0.61)	(0.59)
Operating expenses	(0.75)	(0.83)
Operating netback - natural gas properties	3.67	5.36
Crude oil properties (\$/bbl)		
Sales price - before hedging	63.91	64.08
Hedging settlements	-	-
Royalties	(9.94)	(11.75)
Transportation expenses	(2.47)	(2.26)
Operating expenses	(9.82)	(9.53)
Operating netback - oil properties	41.68	40.54
All properties (\$/boe)		
Sales price - before hedging	43.55	58.99
Hedging settlements	1.31	-
Royalties	(12.15)	(17.45)
Transportation expenses	(3.60)	(3.47)
Operating expenses	(4.75)	(5.34)
Operating netback - all properties	24.36	32.73

General and Administrative Expenses

For the year, general and administrative expenses ("G&A"), net of operator recoveries and capitalized expenses were \$1.7 million (\$0.88 per boe) compared to \$1.1 million (\$0.98 per boe) in the prior year. The Company incurred higher technical service fees from Progress Energy Trust ("Progress"), as compared to the prior year due to the Company's increased activity levels and production volumes during the year. Progress provides these services to ProEx on an expense reimbursement basis, based on ProEx's monthly capital activity and production levels relative to the combined capital activity and production levels of both Progress and ProEx (computed in accordance to the Technical Services Agreement – see "Relationship with Progress"). Higher gross G&A was partially offset by higher operator recoveries driven off higher capital spending during the year compared to 2005. On a per boe basis, the reduction in G&A was the result of higher production volumes during the year versus the prior year. Management forecasts G&A expenses for 2007 to average in the \$1.00 to \$1.10 per boe range.

(\$ thousands)	2006	2005
Direct expenses	850	701
Technical services fee from Progress	4,521	2,759
Gross G&A	5,371	3,460
Operator recoveries	(2,676)	(1,582)
Capitalized expenses	(993)	(752)
Total G&A	1,702	1,126
Total G&A (\$/boe)	0.88	0.98

Interest and Financing Expense

For the year, interest and financing charges were \$1.3 million (\$0.68 per boe) compared to \$0.1 million (\$0.10 per boe) in the prior year. The increase in interest and financing charges for the year as compared to the prior year, is a result of the Company utilizing higher levels of the available credit facility to fund the increased capital activity during the year. Details of ProEx's bank debt are described in Note 4 in the financial statements attached.

Stock Based Compensation Expense

During the year, the Company expensed \$0.8 million in stock based compensation expense related to outstanding stock options and Class B performance shares, compared to \$0.4 million in the prior year. The increase is due to the issuance of 324,000 stock options during the year.

Depletion, Depreciation and Accretion Expense

For the year, depletion and depreciation of capital assets and the accretion of the asset retirement obligations ("DD&A") was \$21.5 million compared to \$11.4 million for the prior year. On a boe basis, DD&A expense for the year was \$11.17 compared to \$9.89 for the prior year. This was a result of higher proved finding and development costs during 2006 compared to 2005 and the inclusion of higher future development capital estimates to exploit future opportunities.

(\$ thousands)	2006	2005
Depletion	21,357	11,298
Depreciation	3	2
Accretion	183	117
Total depletion, depreciation and accretion	21,543	11,417
DD&A (\$/boe)	11.17	9.89
Depletion and depreciation rate (%)	10.6	13.9

Future Income Taxes

Future income tax expense for 2006 was \$6.4 million (29.8 percent effective rate) compared to \$9.6 million (38.7 percent effective rate) in the prior year. The current year provision includes a recovery of \$0.9 million relating to a reduction in future federal and provincial income tax rates enacted during the year. The Company has approximately \$226 million of federal tax pools to shelter taxable income in future years. The federal tax pools are as follows:

(\$ thousands)	2006	2005
Canadian Exploration Expense	61,000	32,000
Canadian Development Expense	74,000	25,500
Canadian Oil and Gas Property Expense	44,000	31,500
Undepreciated Capital Cost	42,000	23,000
Other	5,000	2,000
Total tax pools	226,000	114,000

Net Earnings and Funds Generated from Operations

Net earnings for the year of \$15.2 million is consistent with the \$15.0 million for the prior year. Basic net earnings per share for the year was \$0.43 per share (\$0.49 per share in 2005), while diluted net earnings per share for the year was \$0.36 (\$0.40 per share in 2005). Funds generated from operations increased 21 percent to \$43.5 million for the year, compared to \$36.0 million in the prior year. Funds generated from operations per basic share for the year was \$1.23 per share (\$1.17 per share in 2005), while funds generated from operations per diluted share for the year was \$1.04 (\$0.96 per share in 2005). On a per boe basis, net income was \$7.86 per boe during the year compared to \$13.01 in the prior year. Funds generated from operations was \$22.57 per boe during the year compared to \$31.23 per boe in the prior year. The decrease in net earnings and funds generated from operations per boe reflects the reduced natural gas price environment as compared to the prior year, which was largely offset by the Company's 67 percent increase in production over the same period.

The following table summarizes the netbacks, funds generated from operations and net earnings on a barrel of oil equivalent basis for the year and the prior year:

(\$/boe)	2006	2005
Petroleum and natural gas revenues (including hedging settlements)	44.85	58.99
Royalties	(12.15)	(17.45)
Interest income	-	0.02
	32.70	41.56
Operating expenses	(4.75)	(5.34)
Transportation expenses	(3.60)	(3.47)
Operating netback	24.35	32.75
General and administrative expenses	(0.88)	(0.98)
Interest expenses	(0.68)	(0.10)
Asset retirement expenditures ⁽¹⁾	(0.22)	(0.33)
Capital taxes	-	(0.11)
Funds generated from operations	22.57	31.23
Asset retirement expenditures ⁽¹⁾	0.22	0.33
Stock based compensation expense	(0.43)	(0.39)
Depletion, depreciation and accretion expenses	(11.17)	(9.89)
Net earnings before taxes	11.19	21.28
Future income taxes	(3.33)	(8.27)
Net earnings	7.86	13.01

⁽¹⁾ Actual asset retirement costs incurred during the year are classified for cash flow purposes on the statement of cash flows as an operating item, however these costs are not an expense of the period and are therefore added back for purposes of determining net earnings.

COMMON SHARE INFORMATION

<i>(thousands)</i>	2006	2005
Weighted average outstanding common shares		
- Basic	35,336	30,687
- Diluted	41,749	37,522
Outstanding securities at December 31,		
- Common shares	39,691	32,998
- Common share options	778	472
- Common share warrants	6,144	6,585
- Diluted common shares outstanding	46,613	40,055
- Class B performance shares	695	695
Outstanding securities at February 23, 2007		
- Common shares	39,791	
- Common share options	780	
- Common share warrants	6,048	
- Diluted common shares outstanding	46,619	
- Class B performance shares	695	

Per Share Information

<i>(\$ thousand, except per share amounts)</i>	2006	2005
Net earnings	15,163	15,015
Net earnings per share		
- Basic	0.43	0.49
- Diluted	0.36	0.40
Funds generated from operations	43,531	36,044
Funds generated from operations per share		
- Basic	1.23	1.17
- Diluted	1.04	0.96
Proved plus probable reserves <i>(mboe)</i>	31,513	15,028
Proved plus probable reserves per thousand shares <i>(boe)</i>		
- Basic ⁽¹⁾	794	455
- Diluted ⁽²⁾	676	375
Average Production <i>(boe/d)</i>	5,285	3,162
Average Production per million shares <i>(boe/d)</i>		
- Basic ⁽³⁾	149.6	103.0
- Diluted ⁽⁴⁾	126.6	84.3
Fourth quarter production <i>(boe/d)</i>	6,080	4,561
Fourth quarter production per million shares <i>(boe)</i>		
- Basic ⁽¹⁾	153.2	138.2
- Diluted ⁽²⁾	130.4	113.9

⁽¹⁾ Calculated using outstanding common shares at the end of the year.

⁽²⁾ Calculated using outstanding common shares, options and warrants at the end of the year.

⁽³⁾ Calculated using the weighted average outstanding common shares at the end of the year.

⁽⁴⁾ Calculated using the weighted average outstanding common shares, options and warrants at the end of the year.

On a per share basis, net earnings for the year decreased 12 percent over the prior year, while on a diluted basis, net earnings per share decreased 10 percent. Funds generated from operations per basic share increased by five percent during the year while funds generated from operations per diluted share increased eight percent during the same period.

Average production per million basic shares increased 45 percent during the year while average production per one million diluted shares increased 50 percent during the same period.

Proved plus probable reserves per thousand basic shares increased 75 percent over the prior year while proved plus probable reserves per one thousand diluted shares increased 80 percent during the same period.

NET ASSET VALUE BEFORE TAX⁽¹⁾

ProEx's net asset value per share at December 31, 2006 was \$10.60 per basic share (\$7.70 per basic share in 2005) and on a diluted basis \$9.38 per share (\$6.67 per diluted share in 2005) using GLJ Petroleum Consultants Ltd. ("GLJ") forecasted prices discounted at 10 percent, and \$11.90 per basic share and \$10.49 per diluted share (\$8.74 and \$7.20 respectively per share in 2005) using GLJ forecasted prices discounted at eight percent. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101.

(\$ thousands)	2006		2005	
	PV 8%	PV 10%	PV 8%	PV 10%
Proved plus probable reserve value (10% discount before tax) ⁽²⁾	420,517	369,355	235,090	214,326
Undeveloped acreage ⁽³⁾	63,000	63,000	40,000	40,000
Seismic ⁽⁴⁾	17,000	17,000	10,000	10,000
Bank debt	(25,803)	(25,803)	-	-
Working capital deficiency	(2,035)	(2,035)	(9,275)	(9,275)
Asset retirement obligations ⁽⁵⁾	(478)	(925)	(506)	(980)
Net asset value - Basic	472,201	420,592	275,309	254,071
Exercise of stock options and warrants	16,813	16,813	13,104	13,104
Net asset value - Diluted	489,014	437,405	288,413	267,175
Common shares outstanding				
-Basic	39,691	39,691	32,998	32,998
-Diluted	46,613	46,613	40,055	40,055
Net asset value per common share (\$)				
-Basic	11.90	10.60	8.74	7.70
-Diluted ⁽⁶⁾	10.49	9.38	7.20	6.67

⁽¹⁾ The Company's net asset value before tax is measured with reference to the present value of future estimated net cash flows from reserves estimated by GLJ, the independent reserve engineers, and including land, seismic data, adjustments for working capital deficiency, asset retirement obligations and bank debt at year end. This calculation can vary significantly depending on the natural gas and oil price assumptions used by GLJ. This calculation does not represent a "going-concern" value since it only assumes the reserves contained in the GLJ report.

⁽²⁾ Reserve values are based on before tax estimates of future cash flows as evaluated by our independent qualified reserve evaluators, GLJ using their future commodity price forecast as presented in the pricing assumptions (see 2006 Annual Information Form).

⁽³⁾ Undeveloped land values are based on internal estimates of market value considering recent sales of similar properties in the same general area. The Company's historic cost is approximately \$52 million.

⁽⁴⁾ Seismic inventory values are an internal estimate of replacement value.

⁽⁵⁾ Proved plus probable reserve value includes \$1.3 million (2005 - \$0.9 million) at PV eight percent, and \$0.9 million (2005 - \$0.4 million) at PV ten percent forecast pricing, of asset retirement obligations on wells with assigned reserves.

⁽⁶⁾ Calculated using outstanding common shares, options and warrants at year-end.

INVESTMENT AND INVESTMENT EFFICIENCIES

Capital Investment

During the year the Company invested approximately \$152.2 million with the drilling of 63 gross wells (44.0 net) for a success rate of 95 percent (96 percent net). The following table summarizes the capital investments for the year and the prior year.

(\$ thousands)	2006	2005
Land acquisitions and retention	17,146	7,682
Geological and geophysical	10,252	11,781
Drilling and completions	95,913	55,872
Equipping and facilities	28,158	18,779
Corporate assets	9	-
Total exploration and development capital	151,478	94,114
Net property acquisitions (disposition)	683	(8,660)
Total capital expenditures	152,161	85,454

Drilling results

	2006		2005	
	Gross	Net	Gross	Net
Crude oil	3	1.3	4	0.8
Natural gas	57	41.0	37	26.2
Dry and abandoned	3	1.7	4	1.6
Total	63	44.0	45	28.6
Success rate (%)	95	96	91	94

Undeveloped Land

ProEx has undeveloped land at year end of approximately 271,000 net acres and in addition has access to approximately 14,000 acres of option lands for a total acreage under its control of approximately 285,000. Approximately 246,000 net acres (91 percent) of the undeveloped lands are in the Foothills region of northeast British Columbia and ProEx's average interest in these lands is 76 percent. Including option lands, ProEx has 260,000 acres or 91 percent of its acreage in the Foothills region. The balance of the northeast British Columbia undeveloped lands are in the Fort St. John Plains region where the Company has an average working interest of 20 percent.

Undeveloped Land Additions

ProEx has purchased, acquired through farm-in or bought at Crown land sales approximately 125,141 net acres during the year. ProEx has an average working interest in its undeveloped land base of 60 percent which is an increase from 50 percent in 2005. ProEx continues to generate opportunities to earn land through farm-ins with 22 sections of option lands available to it at December 31, 2006. Over the next twelve months, 14 percent of ProEx net undeveloped acreage will be subject to expiry. With an active drilling program, ProEx anticipates minimal undeveloped acres expiring in 2007.

Option Land Additions

At December 31, 2006, ProEx has 13,885 gross acres of land in its core areas in British Columbia on which it has the option to earn an interest. Of these option lands, 100 percent are in the Foothills region of British Columbia. These lands are subject to various agreements whereby the Company must perform certain activities to earn an interest in the lands. The term of these agreements extend through various terms to August 2007.

	2006		2005	
	Gross	Net	Gross	Net
Foothills – British Columbia	322,000	246,000	185,000	135,000
Fort St. John Plains – British Columbia	126,000	25,000	136,000	26,000
Total owned British Columbia undeveloped lands	448,000	271,000	321,000	161,000
Total controlled British Columbia option lands	14,000	-	47,000	-

Finding & Development Costs

Advisory

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development capital generally will not reflect total finding and development costs related to reserve additions for that year.

During 2006, the exploration and development program resulted in total reserve additions (after revisions) of 9.9 million boe on a proved basis, and 16.5 million boe on a proved plus probable basis resulting in the total exploration and development program finding, development and acquisition costs ("FD&A") of \$12.87 per boe proved and \$8.26 per boe proved plus probable. After incorporating the change in future development capital, the exploration and development program generated finding and development costs of \$15.70 per boe proved and \$10.93 per boe proved plus probable. The cumulative FD&A costs (including change in future development capital) for the period July 1, 2004 to December 31, 2006 are \$13.80 per boe proved and \$10.37 per boe proved plus probable.

2006 Finding & Development Costs and Finding, Development & Net Acquisition Costs	Capital	Proved	Proved	Proved Plus Probable	Proved Plus
	Expenditures	Reserve Additions	Costs	Reserve Additions	Probable Costs
	(\$ thousands)	(mboe)	(\$/boe)	(mboe)	(\$/boe)
F&D exploration and development program before revisions	151,468	12,434	12.18	19,348	7.83
F&D exploration and development program after revisions (a)	151,468	11,823	12.81	18,403	8.23
Change in proved future development capital (b) ⁽¹⁾	33,418	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c) ⁽¹⁾	49,167	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d) = (a+b)	184,886	11,823	15.64	n/a	n/a
Proved plus probable F&D including change in future development capital (e) = (a+c)	200,635	n/a	n/a	18,403	10.90
Net acquisition/disposition activity (f)	684	-	n/c ⁽²⁾	12	57.00
Total 2006 proved FD&A costs including future development capital (d+f)	185,570	11,823	15.70	n/a	n/a
Total 2006 proved plus probable FD&A costs including future development capital (e+f)	201,319	n/a	n/a	18,414	10.93

⁽¹⁾ The acquisition activity during the year consisted of undeveloped land with no associated reserves.

*2005 Finding & Development Costs and
Finding, Development & Net Acquisition Costs*

	Capital Expenditures	Proved Reserve Additions	Proved Costs	Proved Plus Probable Reserve Additions	Proved Plus Probable Costs
	(\$ thousands)	(mboe)	(\$/boe)	(mboe)	(\$/boe)
F&D exploration and development program before revisions	94,114	7,883	11.94	9,845	9.56
F&D exploration and development program after revisions (a)	94,114	8,120	11.59	9,743	9.66
Change in proved future development capital (b) ⁽¹⁾	8,189	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c) ⁽¹⁾	6,553	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d) = (a+b)	102,303	8,120	12.60	n/a	n/a
Proved plus probable F&D including change in future development capital (e) = (a+c)	100,667	n/a	n/a	9,743	10.33
Net acquisition/disposition activity (f)	(8,660)	(298)	(29.06)	(405)	(21.38)
Total 2005 proved FD&A costs including future development Capital (d+f)	93,643	7,822	11.97	n/a	n/a
Total 2005 proved plus probable FD&A costs including future development capital (e+f)	92,007	n/a	n/a	9,338	9.85

*2004 to 2006 Finding & Development Costs and
Finding, Development & Net Acquisition Costs*

	Capital Expenditures	Proved Reserve Additions	Proved Costs	Proved Plus Probable Reserve Additions	Proved Plus Probable Costs
	(\$ thousands)	(mboe)	(\$/boe)	(mboe)	(\$/boe)
F&D exploration and development program before revisions	277,442	23,869	11.62	34,001	8.16
F&D exploration and development program after revisions (a)	277,442	23,443	11.83	32,800	8.46
Change in proved future development capital (b) ⁽¹⁾	45,371	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c) ⁽¹⁾	62,098	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d) = (a+b)	322,813	23,443	13.77	n/a	n/a
Proved plus probable F&D including change in future development capital (e) = (a+c)	339,540	n/a	n/a	32,800	10.35
Net acquisition/disposition activity (f)	(3,470)	(298)	(11.64)	(393)	(8.83)
Total 2004 and 2005 proved FD&A costs including future development capital (d+f)	319,343	23,145	13.80	n/a	n/a
Total 2004 and 2005 proved plus probable FD&A costs including future development capital (e+f)	336,070	n/a	n/a	32,406	10.37

⁽¹⁾ Reconciliation of Changes in Future Development Capital

(\$ thousands)	Proved	Change	Proved Plus Probable	Change
July 2, 2004	1,118		1,729	
		3,764		6,378
January 1, 2005	4,882		8,107	
		8,189		6,553
January 1, 2006	13,071		14,660	
		33,418		49,167
January 1, 2007	46,489		63,827	

Production Replacement

The Company's capital investment program during the year replaced production by a factor of 6.1 times on a proved basis and 9.5 times on a proved plus probable basis.

	2006	2005
Production (mboe)	1,929	1,154
Proved reserve additions after revisions of prior periods and net acquisitions (mboe)	11,823	7,822
Proved replacement ratio	6.1	6.8
Proved plus probable reserve additions after revision of prior periods and net acquisitions (mboe)	18,414	9,338
Proved plus probable replacement ratio	9.5	8.1

Recycle Ratio

The recycle ratio is a measure for evaluating the effectiveness of a company's re-investment program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the operating netback per boe of oil equivalent to that year's reserve FD&A costs.

	2006	2005
Operating netbacks (\$/boe)	24.36	32.73
Proved FD&A costs after revisions of prior periods and including the change in future development capital (\$/boe)	15.70	11.97
Proved reinvestment efficiency ratio	1.6	2.7
Proved plus probable FD&A costs after revisions of prior periods and including the change in future development capital (\$/boe)	10.93	9.85
Proved plus probable reinvestment efficiency ratio	2.2	3.3

CAPITALIZATION AND CAPITAL RESOURCES

The Company's total capitalization was \$550.9 million at December 31, 2006 with a market value of common shares representing 93 percent of total capitalization and total debt representing 5 percent of total capitalization. The market value of the Company's common shares at December 31, 2006 was \$510.0 million compared to \$541.2 million in the prior year.

(thousands except per share amounts)	%	2006	%	2005
Common shares outstanding		39,691		32,998
Share price ⁽¹⁾		12.85		16.40
Total market capitalization	93	510,029	97	541,167
Working capital deficiency		2,035		9,275
Bank debt		25,803		-
Total debt	5	27,838	2	9,275
Asset retirement obligations	-	1,791	-	1,426
Future income tax liability (asset)	2	11,291	1	6,259
Total capitalization	100	550,949	100	558,127
Total debt to total capitalization (%)		5		2

⁽¹⁾ Represents the closing price on the TSX on December 31.

The Company has a \$100 million credit facility available on which \$25.8 funds were drawn at December 31, 2006. At December 31, 2006 the Company had a working capital deficit of \$2.0 million resulting in total net debt of \$27.8 million. The ratio of total net debt as at December 31, 2006 to 2006 funds generated from operations was 0.6 times and the ratio of total net debt as at December 31, 2006 to the annualized fourth quarter funds generated from operations was 0.5 times. The 2007 capital program will be funded by funds generated from operations and bank debt.

Investing Program Funding

(\$ thousands)	2006	2005
Cash and short term investments, beginning of year	667	2,112
Funds generated from operations	43,531	36,044
Changes in non-cash working capital	(7,906)	(3,851)
Issue of common shares (net of share issue costs)	90,066	51,816
Increase in bank debt	25,803	-
Less cash and short term investments, end of period	-	(667)
Capital expenditures during the year	152,161	85,454

The Company's 2006 capital investment program was funded by funds generated from operations and two equity offerings during the year. On May 17, 2006 the Company issued 3.0 million common shares at a price of \$16.15 per common share resulting in gross proceeds of \$48.5 million (\$46.3 million net of issue costs). On November 30, 2006 the Company issued 2.0 million common shares at a price of \$12.40 per common share and 1.3 million flow-through common shares at a price of \$16.25 per flow-through share resulting in aggregate gross proceeds of \$45.1 million (\$43.1 million net of issue costs).

Bank Facility

The Company has a \$100 million demand revolving operating credit facility. The Company's credit facility is with a Canadian bank and is reviewed twice per year. The facility is a borrowing base facility that is determined based on, among other things, the Company's current reserve report, results of operations, current and forecasted commodity prices and the current economic environment. At December 31, 2006, \$25.8 million was drawn on the available credit facility.

Working Capital

The capital intensive nature of the Company's activities may create a negative working capital position in quarters with high levels of capital investment. Working capital deficiency decreased from \$9.3 million as at December 31, 2005 to \$2.0 million as at December 31, 2006 due to increased accounts receivable as a result of increased production in December 2006 compared to December 2005.

Substantially all of the Company's petroleum and natural gas production is marketed by Progress Energy Trust under standard industry terms and in accordance with the terms of the Technical Services Agreement. Accounts payable consist of amounts payable to suppliers, field operating activities and capital spending activities. These invoices are processed within the Company's normal payment period. At December 31, 2006 the Company had no material accounts receivable that it deemed uncollectible.

The Company actively manages the pace of its capital spending program by monitoring forecasted production and commodity prices and resulting funds generated from operations. Should circumstances affect funds generated from operations in a detrimental way, the Company is capable of reducing capital activity levels.

Off-Balance Sheet Arrangements

ProEx has entered into derivative financial instruments to hedge future natural gas sales and has committed to pay the associated premiums of these contracts. These derivative contracts, accounted for as hedges, are not recognized on the balance sheet. The contracts currently in place are disclosed in note 9 to the financial statements and also in the "Risk Management" section of the MD&A. Future premium obligations are disclosed below under "Contractual Obligations and Commitments". ProEx has no other off-balance-sheet arrangements.

Contractual Obligations and Commitments

As part of the Company's land capture strategy, it will commit to industry partners to drill wells, and or shoot seismic in order to earn positions in contiguous land blocks. As at December 31, 2006, ProEx had commitments to drill and complete one well costing approximately \$1.2 million (net) in 2007 which will earn lands from area competitors in the Foothills region of northeast British Columbia. These commitments are scheduled in the Company's 2007 capital investment plans.

The Company must pay Crown royalties, surface rentals, mineral taxes and abandonment and reclamation costs with respect to its ongoing ownership of hydrocarbon production rights. The amount paid with respect to these burdens will depend on the future ownership, production, commodity prices and regulatory environment at the time.

During the year, the Company finalized a five year commitment for raw gas transmission and treatment on the regulated British Columbia natural gas system.

In addition, the Company has entered into certain derivative financial instruments under its commodity risk management program, the terms and commitments of which are disclosed in note 9 of the financial statement.

The Company's future contractual commitments are highlighted below.

(\$ thousands)	Total	2007	2008	2009	2010	2011	2012
Farm-in commitments	1,200	1,200	-	-	-	-	-
Gas transmission and treatment ⁽¹⁾	37,524	8,294	8,817	8,547	6,974	4,892	-
Drilling rig commitments	5,424	3,103	2,321	-	-	-	-
Operating leases	3,206	1,838	1,368	-	-	-	-
Financial instrument premiums	2,251	2,251	-	-	-	-	-
Total contractual obligations	49,605	16,686	12,506	8,547	6,974	4,892	-

⁽¹⁾ The Company has reflected the contractual option to reduce contracted volume amounts by 20 percent per year in the final two years of the contract in the numbers presented above.

OUTLOOK AND 2007 BUDGET

With the Company's extensive exploration and development drilling inventory, undeveloped land position, low finding costs and balance sheet strength, it is well positioned to capitalize on its opportunities in 2007 and beyond. Our exploration land base in northeast British Columbia has grown very rapidly to approximately 285,000 acres under our control. With the results from our 2006 drilling program and a total of approximately 1,000 square kilometers of 3-D seismic data in the Foothills, we have developed an extensive knowledge of the subsurface and the opportunities to expand the Halfway tight gas play as well as Cretaceous section.

We expect to invest approximately \$120 million in 2007, primarily in the Foothills region in northeast British Columbia. Approximately 20 percent of the capital program will be invested in land capture and seismic data acquisition to continuously expand our inventory of drilling opportunities. We are targeting average production for 2007 of between 8,500 to 9,000 boe per day and exiting the year between 9,500 to 10,000 boe per day. We anticipate funding our 2007 growth program with funds generated from operations and the existing bank debt facility.

2007 Sensitivities

Based on the above assumptions, the following sensitivities are provided to demonstrate the impact on funds generated from operations and net earnings of changes in commodity prices, and the Canadian currency.

<i>(\$ thousand)</i>	Funds generated from operations	Net earnings
Impact on the year ended December 31, 2007		
- Change in West Texas Intermediate oil price by US\$1.00 per barrel	\$142	\$96
- Change in average field price of natural gas by Cdn \$1.00 per mcf	\$12,600	\$8,500
- Change in value of Cdn dollar compared to US dollar by Cdn \$0.01	\$1,004	\$734

SELECTED QUARTERLY INFORMATION AND FOURTH QUARTER ANALYSIS

	Q4 2006	Q3 2006	Q2 2006	Q1 2006	Q4 2005
Operational Results					
Production					
-Natural gas (mcf/d)	33,505	28,348	29,931	23,454	24,942
-Crude oil (bbls/d)	343	331	352	314	316
-Natural gas liquids (bbls/d)	152	148	163	112	88
-Total production (boe/d)	6,080	5,204	5,503	4,335	4,561
Pricing					
-Natural gas (\$/mcf)	7.53	6.19	6.34	8.50	11.96
-Crude oil (\$/bbl)	60.87	75.56	74.72	65.66	67.99
-Natural gas liquids (\$/bbl)	56.35	71.46	72.41	68.00	69.25
Selected Financial Results (\$ thousands, except per share amounts)					
Petroleum and natural gas revenue (including hedging)	25,910	19,419	20,723	24,472	29,984
Royalties	6,367	5,203	5,823	6,048	9,561
Operating expenses	2,586	2,421	2,350	1,816	1,878
General and administrative expenses	361	420	543	377	504
Funds generated from operations	13,995	8,766	10,118	10,653	16,501
Depletion, depreciation and accretion expense	7,600	4,916	5,245	3,782	4,062
Net earnings	4,293	2,627	3,978	4,265	7,775
-Basic per share	0.11	0.07	0.12	0.13	0.24
-Diluted per share	0.10	0.06	0.10	0.11	0.20
Capital Spending					
-Exploration and development	43,484	32,054	25,436	50,495	28,713
-Net acquisitions and dispositions	53	388	198	44	17
-Corporate assets	-	-	9	-	-
Total capital expenditures	43,537	32,442	25,643	50,539	28,730
Bank debt and working capital deficiency (surplus)	27,838	41,499	18,364	49,126	9,275
Shareholders' equity	225,398	176,968	173,625	122,422	117,951
Common shares outstanding	39,691	36,380	36,021	33,003	32,997

Production

Production during the fourth quarter of 2006 increased 17 percent to 6,080 boe per day compared to 5,204 boe per day in the prior quarter. The production increase was the result of successful drilling during the third and fourth quarters of 2006. Production additions were generated primarily in the West Beg and Dogrib areas of the Foothills region of northeast British Columbia with production that increased from 2,345 boe per day in the prior quarter to 3,107 boe per day in the fourth quarter. Production during the fourth quarter increased by 33 percent from 4,561 boe per day recorded in the fourth quarter of 2005 due to the success of the 2006 capital program.

Petroleum and Natural Gas Revenues

Petroleum and natural gas revenues (including hedging settlements) for the fourth quarter of 2006 increased 34 percent to \$25.9 million compared to the prior quarter of \$19.4 million. Contributing to the increase over the prior quarter was the increase in production and a 22 percent increase in realized natural gas prices to \$7.53 per mcf in the fourth quarter compared to \$6.19 per mcf in the third quarter. Natural gas prices for the fourth quarter benefited from hedging settlements beginning in November, which amounted to \$0.82 per mcf, prior to which no hedging contracts were in place. A 33 percent increase in production in the fourth quarter of 2006 over the same period in 2005 largely offset the decline in natural gas prices during the same period which resulted in a 13 percent decline in revenues to \$25.9 million in the fourth quarter of 2006 from \$29.9 million recorded in the fourth quarter of 2005. The Company's realized natural gas price in the fourth quarter of 2005 was \$11.96 per mcf, 59 percent higher than the \$7.53 recorded in the current period.

Royalties

Royalties for the fourth quarter of 2006 increased 23 percent to \$6.4 million over the prior quarter of \$5.2 million. The average royalty rate (excluding the impact of hedging settlements) increased from 26.8 percent in the third quarter to 27.2 percent in the fourth quarter of 2006 due to increased commodity prices during the same period. The 14 percent decrease in the fourth quarter of 2006 royalty rate over the fourth quarter of 2005 rate of 31.8 percent, is primarily a result of the decline in commodity prices during the same period.

Operating Expenses

Operating expenses for the fourth quarter of 2006 were \$2.6 million compared to the third quarter of \$2.4 million. On a boe basis, operating expenses in the fourth quarter decreased nine percent to \$4.62 from the \$5.06 recorded in the third quarter. The third quarter operating costs included repair and maintenance work which resulted in higher than average operating costs. Operating expenses during the fourth quarter of 2005 of \$4.48 per boe are consistent with the fourth quarter rate.

Transportation Expenses

Transportation expenses for the fourth quarter of 2006 were \$2.0 million (\$3.64 per boe), consistent on a per boe basis with the prior quarter expense of \$1.7 million (\$3.56 per boe). Transportation expenses in the fourth quarter of 2005 were \$1.4 million (\$3.37 per boe). Higher transportation expense per boe in the current quarter as compared to the same quarter in the prior year reflects the increased toll rates contracted in B.C. with Duke Energy. In British Columbia, Duke Energy owns the infrastructure that enables gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

General and Administrative Expenses

For the fourth quarter of 2006, G&A expenses were \$0.4 million consistent with the prior quarter, and 20 percent lower than the \$0.5 million recorded in the fourth quarter of 2005. On a per boe basis, G&A expenses decreased 26 percent from \$0.88 per boe in the prior quarter to \$0.65 in the fourth quarter of 2006 and decreased 47 percent from \$1.20 recorded in the fourth quarter of 2005. The decrease in G&A expenses over the fourth quarter of 2005 is primarily a result of increased operator recoveries resulting from increased capital spending levels. The decrease in G&A per boe over the prior quarter and the same period in the prior year is due to increased production volumes.

(\$ thousands)	Q4 2006	Q3 2006	Q4 2005
Direct expenses	451	305	323
Technical services fee from Progress	1,103	915	627
Gross G&A	1,554	1,220	950
Operator recoveries	(867)	(593)	(369)
Capitalized expenses	(326)	(207)	(104)
Total G&A	361	420	477
Total G&A (\$/boe)	0.65	0.88	1.20

Interest and Financing Expenses

Interest and financing expenses for the fourth quarter of 2006 were \$0.5 million compared to the prior quarter of \$0.6 million. On a boe basis, interest and financing expenses in the fourth quarter decreased 25 percent to \$0.93 from the \$1.24 recorded in the prior quarter. The decrease in interest and financing costs per boe over the prior quarter is a result of lower average debt levels, resulting from the November Common Share issuance, along with increased production volumes. Interest and financing expenses during the fourth quarter of 2005 were \$0.1 million (\$0.13 per boe) due to significantly lower average debt levels during the period.

Depletion, Depreciation and Accretion

For the fourth quarter of 2006, DD&A expenses increased 55 percent to \$7.6 million from the \$4.9 million recorded in the third quarter. On a boe basis, DD&A expenses increased 32 percent from \$10.27 in the third quarter to \$13.59 in the fourth quarter. For the fourth quarter of 2005, the Company recorded DD&A expense per boe of \$9.68.

Income taxes

Future income taxes were \$1.9 million for the fourth quarter of 2006 compared to \$1.3 million for the prior quarter due to higher earnings in the fourth quarter. Conversely fourth quarter of 2006 income taxes were lower than the \$4.6 million recorded in the fourth quarter of 2005 due to lower earnings resulting from lower natural gas prices.

Net Earnings and Funds Generated From Operations

Net earnings for the fourth quarter of 2006 increased 65 percent to \$4.3 million (\$0.11 per basic share, \$0.10 per diluted share) from \$2.6 million (\$0.07 per basic share, \$0.06 per diluted share) recorded in the prior quarter. Net earnings in the fourth quarter of 2005 were \$7.8 million (\$0.24 per basic share, \$0.20 per diluted share), driven by substantially higher commodity prices during the same period.

The Company recorded \$14.0 million (\$0.37 per basic share, \$0.32 per diluted share) in funds generated from operations in the fourth quarter, a 61 percent increase over the \$8.7 million (\$0.24 per basic share, \$0.21 per diluted share) recorded in the prior quarter. The Company recorded \$16.5 million (\$0.50 per basic share, \$0.41 per diluted share) of funds generated from operations in the fourth quarter

of 2005, buoyed by higher natural gas prices than realized in the fourth quarter of 2006. The increase in net earnings and funds generated from operations over the prior quarter is due to higher production volumes and commodity prices during the period.

Capital Investment

Capital investment during the fourth quarter of \$43.5 million was 34 percent higher than the \$32.4 million recorded in the prior quarter, and 52 percent higher than the \$28.7 million recorded in the same period in 2005. The fourth quarter of 2006 included \$25.5 million in drilling and completions, \$5.2 million in land acquisitions, \$1.1 million in geological and geophysical activities, and \$11.6 million in facilities.

RELATIONSHIP WITH PROGRESS

Technical Services Agreement

In conjunction with the Plan of Arrangement, ProEx and Progress entered into a Technical Services Agreement which provides for the shared services required to manage ProEx's activities and govern the allocation of G&A expenses between the entities. Under the Technical Services Agreement, ProEx is charged a technical services fee by Progress, on a cost recovery basis, in respect of management, development, exploitation, operations and marketing activities on the basis of relative production and capital expenditures. The technical services fee for 2006 was \$4.5 million (2005 - \$2.8 million).

Protocol Arrangement

In conjunction with the Plan of Arrangement, ProEx assumed the interests in certain of Progress' producing assets and undeveloped land. Through this transaction both ProEx and Progress have joint interests in certain properties and undeveloped lands. The inter-corporate relationship on the governance of these lands is dictated by standard industry agreements. To ensure good governance practices, the Company has a Protocol Arrangement that specifies how the companies will manage the joint lands in specifically identified areas of interest. The arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. The arrangement also outlines the practices to be followed in the event either party enters into areas outside of the identified areas of interest.

Independent Committee of the Board of Directors

Both ProEx and Progress have created independent committees of the Board of Directors to deal with technical services issues. The Committees' mandate includes the following:

- To consider any issues related to the Technical Services Agreement between Progress and ProEx that they consider appropriate or that are directed to the Committee by Management.
- To meet with the Technical Services Committee or similar committee of Progress when appropriate.
- To advise the Board of Directors of decisions by the Technical Services Committee of interpretations, amendments or issues in dispute.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the financial statements in accordance with Canadian GAAP requires management to make judgments and estimates that affect the financial results of the Company. ProEx's management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. A summary of significant accounting policies are presented in Note 1 to the financial statements. The critical estimates are discussed below:

Petroleum and Natural Gas Reserves

All of ProEx's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The evaluation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices.

Depletion Expense

The Company uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development capital is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development capital have a direct impact on depletion expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment, for which any write-down would be charged to depletion and depreciation expense.

Full Cost Accounting Ceiling Test

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion expense.

Asset Retirement Obligations

The asset retirement obligation is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Income Taxes

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by ProEx is accumulated and communicated to the Company's management as appropriate to allow timely decisions regarding required disclosures. The Company's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings, that the Company's internal controls over financial reporting are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Company. It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's internal controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that these controls will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

CHANGE IN ACCOUNTING POLICIES AND RECENT ACCOUNTING PRENOUNCEMENTS

Internal Control Reporting

In March 2006 Canadian Securities Administrators decided to not proceed with proposed multilateral instrument 52-111 Reporting on Internal Control over Financial Reporting and instead proposed to expand multilateral instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. The major changes resulting from this is the CEO and CFO will be required to certify in the annual certificates that they have evaluated the effectiveness of internal controls over financial reporting ("ICOFR") as of the end of the financial year and disclose in the annual MD&A their conclusions about the effectiveness of ICOFR. There will be no requirement to obtain an internal control audit opinion from the issuer's auditors concerning management's assessment of the effectiveness of ICOFR. There is also no requirement to design and evaluate internal controls against a suitable control framework. This proposed amendment is expected to apply for the year ended December 31, 2008. ProEx is continuing with its evaluation of ICOFR to ensure it meets the criteria for the proposed certification for December 31, 2008.

Financial Instruments

The following standards regarding financial instruments are effective for January 1, 2007; 3855 – "Financial Instruments – Recognition and Measurement", 3861 Financial Instruments – Disclosure and Presentation, 1530 – "Comprehensive Income", and 3865 – "Hedges". The standards require all financial instruments other than held-to-maturity investments, loans and receivables, to be included on a company's balance sheet at their fair value. Held-to-maturity investments, loans and receivables would be measured at their amortized cost. The standards create a new statement for comprehensive income that will include changes in the fair value of certain derivative financial instruments. As a result of these new standards, the Company expects not to elect to use hedge accounting beginning January 1, 2007 and will mark-to-market its natural gas derivative contracts under its risk management program. The accounting for hedging relationships for prior fiscal years is not retroactively changed, therefore, no restatement of prior periods is expected as a result of these new standards.

RISK ASSESSMENT

There are a number of risks facing participants in the Canadian oil and gas industry. Some of the risks are common to all businesses while others are specific to the sector. The following reviews the general and specific risks.

Exploration, Development & Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. ProEx's long-term commercial success depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves it may have at any particular time and the production there from will decline over time as such existing reserves are exploited. A future increase in ProEx's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Company will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, ProEx may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by ProEx.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include: delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas release and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although ProEx maintains liability insurance, when available, in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risk typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the

invasion of water into production formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

Finding Oil and gas exploration requires manpower and capital to generate and test exploration concepts. The eventual testing of a concept will not necessarily result in the discovery of economical reserves. ProEx attempts to minimize finding risk by ensuring that:

- The majority of prospects have multi-zone potential.
- Activity is focused in core regions where expertise and experience is greatest.
- Number of wells drilled is large enough to increase the probability of statistical success rates.
- Working interest are targeted at over 60 percent in new prospects.
- Geophysical techniques are utilized where appropriate.

Investment Risk Profile The Company's investment selection process is based on risk analysis to ensure capital expenditures balance the objectives of immediate cash flow growth (development activity) and future cash flow from the discovery or reserves (exploration). This careful prospect selection process can yield consistent and efficient results. The Company focuses its activity in two core regions, allowing it to leverage off its experience and knowledge in these areas further aiding efficiencies. The Company attempts to maintain a broad range of investment choices to limit the investment risk by continually investing a portion of its annual budget to future years. The Company attempts to use farm-outs to minimize risk on plays it considers higher risk.

Production Beyond exploration risk, there is the potential that the Company's oil and natural gas reserves may not be economically produced at prevailing prices. ProEx minimizes this risk by generating exploration prospects internally, targeting high quality projects and attempting to operate the associated project. Operational control allows the Company to control costs, timing, method and sales of production. Production risk is also minimized by concentrating exploration efforts in regions where facilities and infrastructure are ProEx owned, or the Company can control the future development of new facilities and infrastructure.

Reserve Estimates Economically recoverable oil and natural gas reserves (including natural gas liquids), estimated by the Company's independent engineering firm, GLJ Petroleum Consultants Ltd., and the future net cash flows there from are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from actual results. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected there from, may vary. The Company's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Competitive Industry Conditions

The western Canadian oil and natural gas industry has become a very competitive industry for oil and gas properties, undeveloped land, drillable prospects and oil and natural gas industry professionals. The Company was initially seeded with a large undeveloped land base that provided a quality inventory of exploration prospects and attempts to mitigate this future risk by developing its own exploration prospects, and through these efforts build a quality inventory of undeveloped lands and drillable prospects that can fuel future growth. The Company has a Technical Services Agreement with Progress that provides the Company with a quality group of industry professionals to enable it to execute its business plan.

Supply of Service and Production Equipment

The supply of service and production equipment at competitive prices is critical to the ability to add reserves at a competitive cost and produce these reserves in an economic and timely fashion. In periods of increased activity these services and supplies can become difficult to obtain. The Company attempts to mitigate this risk by developing strong long term relationships with suppliers and contractors.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Company will be affected by numerous factors beyond its control. ProEx's ability to market its natural gas may depend upon our ability to acquire space on pipelines that deliver natural gas to commercial markets. We may also be affected by deliverability uncertainties related to the proximity of our reserves to pipelines and processing facilities, and related to operational problems with such pipelines and facilities as well as extensive government and regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of our reserves. ProEx might also elect not to produce from certain wells at lower prices. All of these factors

could result in a material decrease in the Company's net production revenue causing a reduction in its oil and gas acquisition development and exploration activities. In addition, bank borrowings available to use are in part determined by our borrowing base. A sustained material decline in prices from historical average prices could reduce our borrowing base, therefore reducing the bank credit available to us which could require that a portion, or all, of our bank debt be repaid.

Demand for crude oil and natural gas produced by the Company exists within Canada and the US, however, crude oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Demand for natural gas liquids is dictated predominately by demand for petrochemicals in North American and offshore markets. ProEx mitigates the risks as follows:

- Crude oil production is of a high quality and hence not subject to adverse quality differentials.
- Natural gas is connected to mature pipeline infrastructure that operates with minimal interruptions.
- Exploration efforts target high quality oil and liquids rich natural gas reserves.
- Exploration efforts are concentrated in regions where marketing expertise levels are highest.
- Financial instruments are used, where appropriate, to manage commodity price volatility.

Risk Management

From time to time, ProEx may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, we will not benefit from such increases. Similarly, from time to time, ProEx may enter into agreements to fix the exchange rate of Canadian to US dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, we will not benefit from the fluctuating exchange rate.

ProEx has a Risk Management Policy, the objective of which is to ensure cash flow is sufficient to fund the capital program and cover debt payments by reducing the exposure to commodity prices, foreign exchange and interest rate volatility. These objectives may be achieved through the use of financial instruments or through fixed price contracts for the delivery of physical volumes. The program has established targets and guidelines as approved by the Board of Directors from time to time. Effective controls and procedures are in place to ensure that the mandate is followed.

Technology Risks

The Company relies on information technology systems owned and managed by Progress in accordance with the Technical Services Agreement to manage its day to day operations and perform reporting obligations including the preparation of financial statements, reporting to joint partners and various governments in relation to payment of royalties and taxes.

Technical Services Agreement

The Company has a Technical Services Agreement with Progress, whereby Progress provides services required to manage ProEx's activities including management, development, exploitation, operations, administrative marketing activities and information technology systems. The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or at some other date as may be mutually agreed.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time. ProEx's operations may require licenses from various governmental authorities. There can be no assurance that the Company will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". ProEx's exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which may subject it to legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements such as those proposed in Alberta's Bill 32: Climate Change and Emissions Management, may require the reduction of emissions or emissions intensity produced by the Company's operations and facilities. The direct or indirect costs of these regulations may adversely affect the Company's business.

Environmental and Safety Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provisional and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge.

There are potential risks to the environment inherent in the business activities of the Company. ProEx has developed and implemented policies and procedures to mitigate environmental, health and safety (EH&S) risks. These policies and procedures include the corporate EH&S policy, emergency response plans, the corporate EH&S Management System, and other policies and procedures. These policies and procedures are designed to protect and maintain the environment, and public and employer safety, with respect to all corporate operations on behalf of shareholders, employees and the public at large. The Company mitigates environmental and safety risks by maintaining its facilities, complying with all provincial and federal environmental and safety regulations. The Company has estimated asset retirement obligations of \$1.8 million as at December 31, 2006. The Company recognizes period-to-period changes in the liability of the asset retirement obligation resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

Financial and Liquidity Risks – Additional Funding Requirements

The funds generated from operations from the Company's reserves may not be sufficient to fund its ongoing activities at all times. From time to time, ProEx may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. ProEx relies on various sources of funding to support its growing capital expenditure program, including:

- Internally generated cash flow provides the minimum level of funding on which the Company's annual capital expenditures program is based.
- Debt may be utilized to expand capital programs when deemed appropriate.
- New equity, if available and on favorable terms, may be utilized to expand exploration programs and fund acquisitions.

Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate operations. If the revenues from the Company's reserves decrease as a result of lower oil and natural gas prices or otherwise, it will effect its ability to expend the necessary capital to replace its reserves or to maintain its production. If funds generated from operations is not sufficient to satisfy capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable. Neither its articles nor by-laws limit the amount of indebtedness that the Company may incur. The level of indebtedness from time to time, could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. In addition, cash flow is influenced by factors, which the Company cannot control, such as commodity prices, the US/Cdn exchange rate, interest rates and changes to existing government regulations and tax policies. Should circumstances affect cash flow in a detrimental way, ProEx would respond by increasing debt to within the Company's self-imposed debt guideline and/or reducing capital expenditures.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim which could result in a reduction of the revenue received.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in its becoming subject to liability for pollution, blowouts, property damage, personal injury or other hazards. Although prior to drilling ProEx will obtain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, ProEx may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds generated from operations. The occurrence of a significant event that ProEx is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on our financial position, results of operations or prospects.

Conflicts of Interest

Certain directors are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Most notably, all of our officers are also officers of Progress. The potential conflicts of interests between ProEx and Progress are attempted to be mitigated by independent directors of each of the respective entities boards of directors being on committees that oversee the application of the Technical Services Agreement. Conflicts, if any, will be subject to the procedures and remedies of the Alberta Business Corporations Act.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of Canada. The Company is not aware that any claims have been made in respect of its property or assets. However, if a claim arose and was successful this could have an adverse effect on the Company and its operations.

Reliance on Key Personnel

ProEx's success depends in large measure on certain key personnel, including those of Progress. The loss of the services of such key personnel could have a material adverse affect on ProEx. We do not have key person insurance in effect for management. The contributions of these individuals to ProEx's immediate operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of management.

ADDITIONAL INFORMATION

Additional information relating to the Company, is filed on SEDAR and can be viewed at www.sedar.com. Also information can also be obtained by contacting the Company at ProEx Energy Ltd. 1200, 205 – 5th Avenue S.W., Calgary, Alberta, Canada T2P 4B9 or by e-mail at ir@proexenergy.com. Information is also accessible on the Company's web site at www.proexenergy.com.

MANAGEMENTS REPORT

ProEx Energy Ltd.

The management of ProEx Energy Ltd. is responsible for the financial information and operating data presented in this annual report.

The financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this annual report has been prepared on a basis consistent with that in the financial statements.

ProEx Energy Ltd. has designed and maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded.

The Board of Directors is responsible for ensuring that Management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee of the Board of Directors, composed of non-management Directors, meets regularly with management, as well as the external auditors, to discuss auditing (external, internal and joint venture), internal controls, accounting policy and financial reporting matters. The Committee reviews the annual financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board.

The financial statements have been audited by KPMG LLP, the independent auditors, in accordance with generally accepted auditing standards on behalf of the shareholders. KPMG LLP have full and free access to the Audit Committee.



David D. Johnson
President & CEO
ProEx Energy Ltd.



Steven A. Allaire
Vice President, Finance & CFO
ProEx Energy Ltd.

Calgary, Canada
February 26, 2007

AUDITORS' REPORT TO THE SHAREHOLDERS

ProEx Energy Ltd.

We have audited the balance sheets of ProEx Energy Ltd., as at December 31, 2006 and 2005 and the statements of earnings and retained earnings, and cash flows for the years ended December 31, 2006 and 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years ended December 31, 2006 and 2005 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada

February 26, 2007

BALANCE SHEETS

ProEx Energy Ltd.

<i>As at December 31 (\$ thousands)</i>	2006	2005
ASSETS		
Current		
Cash and short-term investments	-	667
Accounts receivable	22,774	14,248
Prepaid expenses and deposits	1,215	368
	23,989	15,283
Property, plant and equipment (Note 3)	266,318	134,910
	290,307	150,193
LIABILITIES		
Current		
Accounts payable and accrued liabilities	26,024	24,558
Bank debt	25,803	-
	51,827	24,558
Asset retirement obligations (Note 5)	1,791	1,426
Future income taxes (Note 7)	11,291	6,259
	64,909	32,243
SHAREHOLDERS' EQUITY		
Share capital and warrants (Note 6)	192,050	100,581
Contributed surplus (Note 6)	1,453	637
Retained earnings	31,895	16,732
	225,398	117,950
Commitments (Note 10)		
	290,307	150,193

See accompanying notes to the financial statements

Approved on behalf of the Board



Gary E. Perron
Director



David D. Johnson
Director

STATEMENTS OF EARNINGS AND RETAINED EARNINGS

ProEx Energy Ltd.

<i>Year ended December 31 (\$ thousands, except per share amounts)</i>	2006	2005
REVENUES		
Petroleum and natural gas	86,524	68,086
Royalties	(23,441)	(20,136)
Interest	3	26
	63,086	47,976
EXPENSES		
Operating	9,172	6,164
Transportation	6,950	4,008
General and administrative	1,702	1,126
Stock based compensation (Note 6)	825	446
Interest and financing	1,307	117
Depreciation, depletion and accretion	21,543	11,417
	41,499	23,278
Net earnings before taxes	21,587	24,698
TAXES		
Capital taxes	-	133
Future income taxes (Note 7)	6,424	9,550
	6,524	9,683
NET EARNINGS	15,163	15,015
Retained earnings, beginning of year	16,732	1,717
Retained earnings, end of year	31,895	16,732
Net earnings per share (Note 6)		
Basic	\$0.43	\$0.49
Diluted	\$0.36	\$0.40

See accompanying notes to the financial statements

STATEMENTS OF CASH FLOWS

ProEx Energy Ltd.

<i>Year ended December 31 (\$ thousands)</i>	2006	2005
Cash provided by (used in)		
OPERATING		
Net earnings	15,163	15,015
Depletion, depreciation and accretion	21,543	11,417
Stock based compensation	825	446
Asset retirement expenditures (Note 5)	(424)	(384)
Future income taxes	6,424	9,550
Funds generated from operations	43,531	36,044
Change in non-cash working capital (Note 8)	(6,134)	(1,261)
	37,397	34,783
FINANCING		
Increase in bank debt	25,803	-
Issue of shares and warrants (net of share issue costs)	90,067	51,816
Change in non-cash working capital (Note 8)	30	(30)
	115,900	51,786
INVESTING		
Capital expenditures	(152,161)	(85,454)
Changes in non-cash working capital (Note 8)	(1,803)	(2,560)
	(153,964)	(88,014)
Decrease in cash and short-term investments	(667)	(1,445)
Cash and short-term investments, beginning of year	667	2,112
Cash and short-term investments, end of year	-	667

See accompanying notes to the financial statements

NOTES TO FINANCIAL STATEMENTS

ProEx Energy Ltd.
December 31, 2006

ProEx Energy Ltd. ("ProEx" or the "Company") was incorporated on April 8, 2004 and commenced commercial operations on July 2, 2004 under a Plan of Arrangement entered into by Progress Energy Ltd. ("Progress"), Cequel Energy Inc., Progress Energy Trust, Cyries Energy Inc. and ProEx. Under the Plan of Arrangement various assets of Progress were transferred to ProEx. At the time of this transaction, Progress and ProEx were related companies resulting in the transfer of assets and related liabilities to ProEx from Progress at their carrying value.

1. SIGNIFICANT ACCOUNTING POLICIES

Nature of Business and Basis of Presentation

ProEx is involved in the exploration, development and production of petroleum and natural gas in British Columbia. The financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles.

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results may differ from those estimates.

Joint Operations

Substantially all of the exploration, development and production activities are conducted jointly with others and accordingly, the Company only reflects its proportionate interest in such activities.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property, plant and equipment and the provision for asset retirement obligations are based on estimates. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

Cash and Short-Term Investments

Cash and short-term investments consist of cash in the bank, less outstanding cheques and short-term deposits with a maturity of less than three months.

Petroleum and Natural Gas Properties

The Company follows the full cost method of accounting for petroleum and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities.

Petroleum and natural gas assets are evaluated at least annually to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the petroleum and natural gas assets. If the carrying value of the petroleum and natural gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using the risk-free rate.

Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20 percent or more, in which case a gain or loss would be recorded.

Depletion, Depreciation and Accretion

Capitalized costs, together with estimated future capital costs associated with proved reserves, are depleted and depreciated using the unit-of-production method based on estimated gross proved reserves of petroleum and natural gas as determined by independent engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil. Costs of significant unproved properties, net of impairments, are excluded from the depletion and depreciation calculation.

NOTES (continued)

Asset Retirement Obligations

The Company records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability. No gains or losses on retirement activities were realized due to settlements approximating the estimates.

Financial Instruments

The Company uses derivative financial instruments from time to time to hedge its exposure to commodity price and foreign exchange fluctuations. The Company may enter into crude oil and natural gas swap contracts, options or collars to hedge its exposure to petroleum and natural gas commodity prices and may enter into foreign exchange forward contracts to hedge anticipated U.S. dollar denominated petroleum and natural gas sales. The derivative financial instruments are initiated within the guidelines of the Company's risk management policy and the Company does not enter into derivative financial instruments for trading or speculative purposes.

The Company designates its derivative financial instruments as hedges and performs the necessary procedures to enable the use of hedge accounting. This includes the formal documentation of the hedge, linking all derivatives to specific assets and liabilities on the balance sheet or specific firm commitments or forecasted transactions and performing assessments of hedge effectiveness. Derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas revenue and funds generated from operations in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract.

Financial instruments that do not qualify for hedge accounting or are not designated as hedges are recorded at their fair value on the balance sheet with changes in the fair value recognized in earnings.

Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

Income Taxes

The Company follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

Flow-through shares

The Company issues flow-through shares from time to time to finance a portion of its exploration and development activities. Pursuant to the terms of these issues, the tax benefits associated with the resource expenditures will be renounced to the shareholders in accordance with income tax legislation. To recognize the renunciation of the tax benefits, the future tax liability is increased and share capital is reduced by the estimated amount of the tax benefits renounced to the shareholders at the time the related expenditures are renounced.

Stock Based Compensation

The Company follows the fair value method for valuing stock option grants and Class B Performance Share issues. Under this method, compensation cost, attributable to stock options granted and Class B Performance Shares issued to officers and directors of ProEx and employees of Progress in their capacity as service providers, is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the stock options and conversion of Class B Performance Shares, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

The Company has not incorporated an estimated forfeiture rate for stock options, and Class B Performance Shares that will not vest, rather, the Company accounts for actual forfeitures as they occur.

2. RELATIONSHIP WITH PROGRESS ENERGY LTD.

In conjunction with the Plan of Arrangement, ProEx and Progress entered into a Technical Services Agreement which provides for the shared services required to manage ProEx's activities and define the allocation of general and administrative expenses between the entities. Under the Technical Services Agreement, ProEx is charged a technical services fee by Progress, on a cost recovery basis, in

NOTES (continued)

respect of management, development, exploitation, operations and marketing activities on the basis of relative production and capital expenditures. For the year ended December 31, 2006, the technical services fee was \$4.5 million (\$2.8 million in 2005). Under the Technical Services Agreement, Progress markets ProEx's natural gas, crude oil and natural gas liquids under standard industry marketing arrangements on a cost recovery basis. The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or at some other date as may be mutually agreed. As contemplated in the Plan of Arrangement, the Company has issued Class B Performance Shares and stock options to officers and directors of ProEx and employees of Progress in their capacity as service providers to ProEx.

ProEx and Progress have joint interest in certain properties and undeveloped land. These joint interest properties are governed by standard industry agreements and in addition, the companies have entered into a Protocol Arrangement that specifies how each company will govern the management of the joint lands in specifically identified areas of interest. The Protocol Arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. Both Progress and ProEx have created independent committees of their board of directors to monitor compliance with the Technical Services Agreement and the Protocol Arrangement.

As at December 31, 2006, accounts receivable included \$4.6 million due from Progress, which includes standard joint venture amounts including revenue. These amounts were received subsequent to the year end.

3. PROPERTY, PLANT AND EQUIPMENT

(\$ thousands)	2006	2005
Petroleum and natural gas properties	300,894	148,126
Accumulated depletion, depreciation	(34,576)	(13,216)
Property, plant and equipment, net	266,318	134,910

During the year ended December 31, 2006, the Company capitalized \$1.0 million of general and administrative expenses (2005 - \$0.8 million) related to exploration and development activities. The calculation of 2006 depletion and depreciation included an estimated \$46.5 million (2005 - \$13.1 million) for future development capital associated with proved undeveloped reserves and excluded \$38.4 million (2005 - \$22.3 million) for the estimated value of unproved properties. Depletion and depreciation expense for the year ended December 31, 2006 was \$21.5 million (2005 - \$11.4 million).

The Company performed a ceiling test calculation at December 31, 2006 resulting in the undiscounted cash flows from proved reserves and the lower of cost and market of unproved properties exceeding the carrying value of oil and gas assets. The prices used in the ceiling test evaluation of the Company's oil and gas assets is summarized in the following chart:

	Crude Oil		Natural Gas
	West Texas Intermediate (Cdn\$/bbl) ⁽¹⁾	Edmonton Par Price (Cdn\$/bbl)	AECO Gas price (Cdn\$/mmbtu)
2007	72.94	70.25	7.20
2008	70.59	68.00	7.45
2009	68.24	65.75	7.75
2010	67.06	64.50	7.80
2011	67.06	64.50	7.85
2012	67.65	65.00	8.15
2013	68.83	66.25	8.30
2014	70.29	67.75	8.50
2015	71.76	69.00	8.70
2016	73.24	70.50	8.90
2017	74.71	71.75	9.10
Thereafter ⁽²⁾	2.0%	2.0%	2.0%

⁽¹⁾ Future prices incorporated a \$0.87 US/Cdn exchange rate.

⁽²⁾ Percentage change of 2.0% represents the change in future prices each year after 2017 to the end of the reserve life.

4. BANK DEBT

The Company has a \$100 million demand revolving operating credit facility with a Canadian chartered bank. The credit facility provides that advances may be made by way of direct advances or bankers' acceptances. Direct advances bear interest at the bank's prime lending

NOTES (continued)

rate plus a variable rate and the bankers' acceptances bear interest at the applicable bankers' acceptance rate plus a variable rate per annum stamping fee. The variable rate charged by the bank is dependent upon the Company's debt to trailing cash flow ratio. The credit facility is secured by a \$250 million fixed and floating charge debenture on the assets of the Company. The \$100 million borrowing base is subject to a semi-annual and annual review by the bank.

5. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the asset retirement obligations is approximately \$16.3 million which will be incurred over the next 42 years with the majority of costs incurred between 2008 and 2020. A credit adjusted risk-free rate of eight percent was used to calculate the fair value of the asset retirement obligations. In 2005, the Company increased the inflation rate used to calculate the obligations from 1.5 percent to 2.0 percent. The impact of this change was an increase to the liability of \$0.1 million.

The following reconciles the Company's asset retirement obligations:

(\$ thousands)	2006	2005
Balance, beginning of year	1,426	1,936
Liabilities incurred	606	762
Liabilities settled	(424)	(384)
Dispositions	-	(1,143)
Revision to estimated cash flows	-	139
Accretion expense	183	116
Balance, end of year	1,791	1,426

6. SHARE CAPITAL

Authorized

Unlimited number of voting Common Shares, without nominal or par value

701,300 Class B Performance Shares, without nominal or par value

Issued	2006		2005	
(\$ thousands, except for share and warrant amounts)	Number	Amount	Number	Amount
Common Shares				
Balance, beginning of year	32,997,815	98,193	27,450,465	45,191
Issued for cash	6,250,000	93,563	5,000,000	53,750
Issued on exercise of Warrants	433,776	759	574,018	1,005
Issued on exercise of Class B Performance shares	-	-	1,962	-
Issued on exercise of Options	10,266	96	2,400	18
Cancelled	(1,198)	(3)	(31,030)	(65)
Share issue costs, net of tax \$1,393 (2005 - \$1,000)		(2,788)		(1,706)
Balance, end of year	39,690,659	189,820	32,997,815	98,193
Warrants				
Balance, beginning of year	6,584,503	2,381	7,220,581	2,600
Exercised	(433,776)	(156)	(574,018)	(207)
Cancelled	(7,188)	(2)	(62,060)	(12)
Balance, end of year	6,143,539	2,223	6,584,503	2,381
Class B Performance Shares				
Balance, beginning of year	694,851	7	701,300	7
Exercised	-	-	(2,150)	-
Cancelled	(190)	-	(4,299)	-
Balance, end of year	694,661	7	694,851	7
Total share capital and warrants at end of year		192,050		100,581

NOTES (continued)

Issue of Common Shares

On February 25, 2005, the Company issued 2.5 million Common Shares at a price of \$9.10 per share. The proceeds, net of share issue costs of \$1.2 million (\$0.8 million net of tax) were \$21.6 million.

On August 23, 2005, the Company issued 2.5 million Common Shares at a price of \$12.40 per share. The proceeds, net of share issue costs of \$1.5 million (\$0.9 million net of tax) were \$29.5 million.

On May 17, 2006 the Company issued 3.0 million common shares at a price of \$16.15 per common share. The proceeds, net of share issue costs of \$2.2 million (\$1.5 million net of tax) were \$46.3 million.

On November 30, 2006 the Company issued 2.0 million common shares at a price of \$12.40 per common share and 1.3 million flow-through common shares at a price of \$16.25 per flow-through share. The aggregate proceeds, net of share issue costs of \$2.0 million (\$1.4 million net of tax) were \$43.1 million. Pursuant to the flow-through share offering, the Company has renounced \$20.3 million of qualifying resource expenditures, effective December 31, 2006, which will be incurred in 2007. The future income tax effect and reduction to share capital will be accounted for in 2007, the date that the Company filed the renouncement documents with the tax authorities.

Earnings per share

Net earnings per Common Share figures have been calculated using the treasury stock method. The following table reconciles the denominators used for the basic and diluted earnings per Common Share calculations.

<i>Weighted Average Common Shares</i>	2006	2005
Basic	35,335,754	30,686,734
Effect of Warrants	5,772,849	6,153,613
Effect of stock options	22,669	47,519
Effect of Class B Performance Shares	617,697	634,218
Diluted	41,748,969	37,522,084

Warrants

One Common Share may be issued for each Warrant at a price of \$1.39 per share. The Warrants vest and are exercisable equally over a three year period starting on the first anniversary date of the issue, June 28, 2005 and expire on June 28, 2008. As at December 31, 2006, 3,773,699 warrants were exercisable.

Stock options

Under the terms of the stock option plan (the "Plan"), directors and officers of ProEx and Progress employees in their capacity as service providers may be granted options to purchase Common Shares. The Plan provides for the granting of up to 10 percent of the issued and outstanding Common Shares of the Company. As at December 31, 2006, the Company could grant up to 3,969,066 options. Options granted under the Plan have a term of five years to expiry and vest equally over a three year period starting on the first anniversary date of the grant. The exercise price of each option equals the market price of the Company's Common Shares on the date of grant.

The following table sets forth a reconciliation of the Plan activity through December 31, 2006.

	Number of options	Weighted average exercise price
Balance, December 31, 2004	224,000	5.72
Granted	250,000	10.83
Exercised	(2,400)	6.75
Balance, December 31, 2005	471,600	8.38
Granted	324,000	13.85
Exercised	(10,266)	(7.76)
Cancelled	(7,000)	(14.64)
Balance, December 31, 2006	778,334	10.63

NOTES (continued)

The following table summarizes stock options outstanding and exercisable under the plan at December 31, 2006.

Range of exercise price	Options outstanding			Options exercisable	
	Number outstanding at year end	Weighted average remaining contractual life	Weighted average exercise price	Number exercisable at year end	Weighted average exercise price
\$5.60 to \$7.95	228,667	2.59	5.82	144,667	5.73
\$9.08 to \$13.16	315,167	3.73	11.34	66,000	10.34
\$13.70 to \$16.50	234,500	4.43	14.38	9,333	15.83
	778,334	3.60	10.63	220,000	7.54

Stock Based Compensation

The Company accounts for its stock based compensation plan using the fair value method. Under this method, a compensation cost is charged over the vesting period for stock options and Class B Performance Shares granted to officers and directors of ProEx and Progress employees in their capacity as service providers, with a corresponding increase to contributed surplus.

The following table reconciles the Company's contributed surplus:

<i>(\$ thousands)</i>	2006	2005
Balance, beginning of year	637	159
Stock based compensation expense		
Stock options	748	296
Class B Performance shares	77	150
Redemption of Common Shares and warrants	5	34
Exercise of Stock Options	(14)	(2)
Balance, end of year	1,453	637

The fair value of the options granted during the year ended December 31, 2006 and December 31, 2005 was estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions and resulting values for grants as follows:

Assumptions	2006	2005
Risk free interest rate (%)	3.97	3.25
Expected life (years)	3.00	3.00
Expected volatility (%)	42.5	40.0
Weighted average fair value of options granted (\$)	5.94	3.54

7. FUTURE INCOME TAXES

The provision for future income taxes in the statements of earnings and retained earnings reflect an effective tax rate which differs from the expected statutory tax rate. Differences were accounted for as follows:

<i>(\$ thousands)</i>	2006	2005
Net earnings before taxes	21,587	24,698
Statutory income tax rate	35.31%	38.24%
Expected income taxes	7,622	9,445
Add (deduct):		
Non-deductible crown charges	2,294	4,154
Resource allowance	(1,943)	(3,329)
Change in provincial/federal tax rates	(1,770)	(656)
Other	221	(64)
Future income tax expense	6,424	9,550

NOTES (continued)

The future income tax liability at December 31, 2006 and December 31, 2005 is comprised of the tax effect of temporary differences as follows:

(\$ thousands)	2006	2005
Property, plant and equipment	13,878	7,905
Asset retirement obligations	(549)	(483)
Loss carry-forward	(90)	-
Share issue costs	(1,731)	(997)
Attributed Canadian Royalty Income	(217)	(166)
Future income tax liability	11,291	6,259

As at December 31, 2006, the Company has federal tax deductions of approximately \$226.0 million (2005 - \$114.0 million) that is available to shelter future taxable income.

8. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

(\$ thousands)	2006	2005
Accounts receivable	(8,526)	(6,944)
Prepaid expenses and deposits	(847)	(301)
Accounts payables and accrued liabilities	1,466	3,394
Change in non-cash working capital	(7,907)	(3,851)
Relating to:		
Financing activities	30	(30)
Investing activities	(1,803)	(2,560)
Operating activities	(6,134)	(1,261)

Interest

(\$ thousands)	2006	2005
Interest paid	(1,210)	(92)
Interest received	3	26

9. FINANCIAL INSTRUMENTS

Fair value of financial assets

The Company's financial instruments recognized in the balance sheet consist of cash and short-term investments, accounts receivable, accounts payable, accrued liabilities and bank debt. The fair value of these financial instruments approximate their carrying amounts due to their short terms to maturity or the indexed rate of interest on the bank debt.

Credit risk

Substantially all of the Company's petroleum and natural gas production is marketed under standard industry terms by Progress in accordance with the Technical Services Agreement. ProEx monitors the financial condition of Progress on a quarterly basis in order to mitigate the concentration of credit risk with this counterparty. All other accounts receivable are with customers and joint venture partners in the petroleum and natural gas business under normal industry sale and payment terms and are subject to normal credit risks. The Company routinely assesses the financial strength of its customers.

Interest rate risk

The Company is exposed to interest rate risk to the extent that changes in market interest rates will impact the Company's debts that have a floating interest rate. The Company had no interest rate swaps or hedges at December 31, 2006.

NOTES (continued)

Commodity Price Contracts

The Company has entered into derivative financial instruments for the purpose of protecting its funds generated from operations from the volatility of natural gas commodity prices. For the year ended December 31, 2006, the Company's natural gas price risk management program had a net gain of \$2.5 million (2005 - nil) which is included in petroleum and natural gas revenue on the statements of earnings.

Contracts outstanding in respect to financial instruments are as follows:

Natural Gas	Volume	Pricing Point	Strike Price (\$gj)	Cost/ Premium	Term
Winter 2006/2007					
Swap - call spread ¹	10,000 gj/d	AECO	Cdn\$9.60– Cdn\$10.60	\$0.38/gj	Nov 01/06 – Mar 31/07
Swap - call spread ¹	7,000 gj/d	AECO	Cdn\$10.00– Cdn\$11.00	\$0.38/gj	Nov 01/06 – Mar 31/07
Weighted average	17,000 gj/d		Cdn\$9.76– Cdn\$10.76	\$0.38/gj	
Summary 2007					
Swap - call spread ¹	20,000 gj/d	AECO	Cdn\$7.40– Cdn\$8.40	\$0.39/gj	Apr 01/07 – Oct 31/07
	20,000 gj/d		Cdn\$7.40– Cdn\$8.40	\$0.39/gj	

¹ Call spread strike prices indicate minimum floor and maximum ceiling

The estimated fair value of the natural gas financial instruments that qualifies for hedge accounting was a gain of \$9.1 million as at December 31, 2006 and represents an approximation of the amount the Company would receive to terminate the contracts at December 31, 2006. These instruments have no carrying value recorded in the financial statements.

10. COMMITMENTS

The Company is committed to future minimum payments for natural gas transmission and processing, operating leases on compression equipment, future minimum payments for drilling rig contracts and future premiums on financial derivative contracts. Payments required under these commitments for each of the next five years are: 2007 - \$16.7 million; 2008 - \$12.5 million; 2009 - \$8.5 million; 2010 - \$7.0 million; and 2011 - \$4.9 million.

2006 SELECTED QUARTERLY INFORMATION

ProEx Energy Ltd.

FINANCIAL HIGHLIGHTS

<i>\$ thousands, except per share amounts)</i>	Three months ended 2006				Annual
	March 31	June 30	Sept. 30	Dec. 31	2006
Income Statement					
Petroleum and natural gas revenues (including hedging)	20,472	20,723	19,419	25,910	86,527
Funds generated from operations	10,653	10,118	8,766	13,995	43,531
Per share – basic	0.32	0.29	0.24	0.37	1.23
Per share – diluted	0.26	0.25	0.21	0.32	1.04
Net earnings	4,265	3,978	2,627	4,293	15,163
Per share – basic	0.13	0.12	0.07	0.11	0.43
Per share – diluted	0.11	0.10	0.06	0.10	0.36
Balance Sheet					
Capital investment					
Land acquisitions and retention	3,487	5,893	2,604	5,162	17,146
Geological and geophysical	4,172	3,577	1,357	1,147	10,252
Drilling and completions	34,876	12,372	23,087	25,578	95,913
Equipping and facilities	7,960	3,603	5,006	11,597	28,158
Net property acquisitions (dispositions)	44	198	388	53	692
	50,539	25,643	32,442	43,537	152,161
Total debt					
Bank debt	37,003	18,509	34,865	25,803	25,803
Working capital deficiency (surplus)	12,123	(145)	6,634	2,035	2,035
	49,126	18,364	41,499	27,838	27,838
Shareholders' equity	122,422	173,625	176,968	225,397	225,397
Share Information <i>(thousands, except per share amounts)</i>					
Shares outstanding at end of period					
– Common	33,003	36,021	36,380	39,688	39,691
Weighted average shares outstanding for the period					
Basic	33,001	34,497	36,255	37,528	35,336
Diluted	40,289	41,151	42,645	43,697	41,749
Volume traded	14,377	7,934	9,894	11,831	44,036
Common share price (\$)					
– High	16.98	16.64	15.65	14.46	16.98
– Low	11.70	12.10	12.00	12.00	11.70
– Closing	14.66	13.53	12.81	12.85	12.85

2006 SELECTED QUARTERLY INFORMATION

ProEx Energy Ltd.

OPERATIONAL HIGHLIGHTS

(\$ thousands, except per share amounts)	Three months ended 2006				Annual
	March 31	June 30	Sept. 30	Dec. 31	2006
Production					
Natural gas (mcf/d)	23,454	29,931	28,348	33,505	28,836
Crude Oil (bbls/d)	314	352	331	343	335
Natural gas liquids (bbls/d)	112	163	148	152	144
Total production (boe/d)	4,335	5,503	5,204	6,080	5,285
Pricing (including hedging)					
Natural gas (\$/mcf)	8.50	6.34	6.19	7.53	7.08
Crude oil (\$/bbl)	65.66	74.72	75.56	60.87	69.26
Natural gas liquids (\$/bbl)	68.00	72.41	71.46	56.35	67.03
Highlights					
Petroleum and natural gas revenues	52.47	41.38	40.56	46.32	44.85
Royalties	(15.50)	(11.63)	(10.87)	(11.38)	(12.15)
Interest income	0.01	-	-	-	-
Operating expenses	(4.65)	(4.69)	(5.06)	(4.62)	(4.75)
Transportation expenses	(3.70)	(3.52)	(3.56)	(3.64)	(3.60)
Operating netback	28.63	21.54	21.07	26.68	24.35
General and administrative expenses	(0.97)	(1.08)	(0.88)	(0.65)	(0.88)
Interest expenses	(0.23)	(0.21)	(1.24)	(0.93)	(0.68)
Asset retirement expenditures	(0.02)	(0.12)	(0.64)	(0.09)	(0.22)
Capital taxes	(0.10)	0.08	-	-	-
Funds generated from operations	27.31	20.21	18.31	25.01	22.57
Asset retirement expenditures	0.02	0.12	0.64	0.09	0.22
Stock based compensation expense	(0.44)	(0.39)	(0.41)	(0.47)	(0.43)
Depletion, depreciation and accretion expenses	(9.70)	(10.47)	(10.27)	(13.59)	(11.17)
Net earnings before taxes	17.19	9.47	8.27	11.04	11.19
Future income taxes	(6.26)	(1.53)	(2.79)	(3.37)	(3.33)
Net earnings	10.93	7.94	5.48	7.67	7.86
Gross Drilling Results					
Natural gas	16	5	18	18	57
Crude oil	1	-	2	-	3
Dry and abandoned	2	-	1	-	3
	19	5	21	18	63
Net Drilling Results					
Natural gas	12.4	4.4	10.5	13.7	41.0
Crude oil	1.0	-	0.3	-	1.3
Dry and abandoned	1.6	-	0.1	-	1.7
	15.0	4.4	10.9	13.7	44.0
Success rate (%)	89	100	98	100	96

2005 SELECTED QUARTERLY INFORMATION

ProEx Energy Ltd.

FINANCIAL HIGHLIGHTS

<i>\$ thousands, except per share amounts)</i>	Three months ended 2005				Annual
	March 31	June 30	Sept. 30	Dec. 31	2005
Income Statement					
Petroleum and natural gas revenues	9,452	11,217	17,434	29,983	68,086
Funds generated from operations	5,001	5,589	8,953	16,501	36,044
Per share – basic	0.18	0.19	0.29	0.50	1.17
Per share – diluted	0.14	0.15	0.23	0.41	0.96
Net earnings	1,737	1,919	3,585	7,774	15,015
Per share – basic	0.06	0.06	0.11	0.24	0.49
Per share – diluted	0.05	0.05	0.09	0.20	0.40
Balance Sheet					
Capital investment					
Land acquisitions and retention	1,017	782	967	4,916	7,682
Geological and geophysical	5,723	2,171	540	3,347	11,781
Drilling and completions	16,060	5,242	17,007	17,563	55,872
Equipping and facilities	7,075	2,906	5,911	2,887	18,779
Net property acquisitions (dispositions)	(12,090)	10	3,403	17	(8,660)
	17,785	11,111	27,828	28,730	85,454
Total debt					
Bank debt	-	5,000	-	-	-
Working capital deficiency (surplus)	2,905	3,455	(2,915)	9,275	9,234
	2,905	8,455	(2,915)	9,275	9,234
Shareholders' equity	73,500	75,505	110,008	117,950	117,950
Share Information <i>(thousands, except per share amounts)</i>					
Shares outstanding at end of period					
– Common	29,950	29,950	32,974	32,998	32,998
Weighted average shares outstanding for the period					
– Basic	28,423	29,950	31,330	32,986	30,687
– Diluted	35,242	36,800	38,251	39,832	37,522
Volume traded	5,273	4,408	11,867	6,588	28,136
Common share price (\$)					
– High	11.80	11.60	17.97	18.50	18.50
– Low	7.61	9.03	10.85	14.52	7.61
– Closing	10.10	10.65	17.97	16.40	16.40

2005 SELECTED QUARTERLY INFORMATION

ProEx Energy Ltd.

OPERATIONAL HIGHLIGHTS

(\$ thousands, except per share amounts)

	Three months ended 2005				Annual
	March 31	June 30	Sept. 30	Dec. 31	2005
Production					
Natural gas (mcf/d)	12,170	12,943	17,255	24,942	16,864
Crude Oil (bbls/d)	242	267	272	316	274
Natural gas liquids (bbls/d)	89	66	66	88	77
Total production (boe/d)	2,359	2,490	3,214	4,561	3,162
Pricing					
Natural gas (\$/mcf)	7.09	7.91	9.54	11.96	9.70
Crude oil (\$/bbl)	58.47	63.48	74.62	67.99	66.49
Natural gas liquids (\$/bbl)	52.32	59.38	69.23	69.25	62.32
Highlights					
Petroleum and natural gas revenues	44.52	49.51	58.96	71.46	58.99
Royalties	(11.00)	(13.02)	(17.89)	(22.79)	(17.45)
Interest income	0.04	0.03	0.01	0.02	0.02
Operating expenses	(5.56)	(6.42)	(5.58)	(4.48)	(5.34)
Transportation expenses	(3.22)	(3.59)	(3.71)	(3.37)	(3.47)
Operating netback	24.78	26.51	31.79	40.84	32.75
General and administrative expenses	(0.35)	(1.33)	(0.84)	(1.20)	(0.98)
Interest expenses	-	(0.16)	(0.08)	(0.13)	(0.10)
Asset retirement expenditures	(0.83)	(0.27)	(0.44)	(0.04)	(0.33)
Capital taxes	(0.04)	(0.08)	(0.15)	(0.06)	(0.11)
Funds generated from operations	23.56	24.67	30.28	39.41	31.23
Asset retirement expenditures	0.83	0.27	0.44	0.04	0.33
Stock based compensation expense	(0.46)	(0.46)	(0.39)	(0.30)	(0.39)
Depletion, depreciation and accretion expenses	(9.74)	(10.78)	(9.63)	(9.68)	(9.89)
Net earnings before taxes	14.19	13.70	20.70	29.47	21.28
Future income taxes	(6.01)	(5.23)	(8.58)	(12.30)	(8.27)
Net earnings	8.18	8.47	12.12	17.17	13.01
Gross Drilling Results					
Natural gas	12	2	9	14	37
Crude oil	1	-	2	1	4
Dry and abandoned	3	-	-	1	4
	16	2	11	16	45
Net Drilling Results					
Natural gas	7.4	1.0	8.2	9.6	26.2
Crude oil	0.2	-	0.4	0.2	0.8
Dry and abandoned	1.4	-	-	0.2	1.6
	9.0	1.0	8.6	10.0	28.6
Success rate (%)	84	100	100	98	94

CORPORATE INFORMATION

Directors

John M. Stewart ^{(1) (4)}
Chairman
ProEx Energy Ltd.
Vice Chairman
ARC Financial Corporation
Scottsdale, Arizona, USA

David D. Johnson
President & Chief Executive Officer
ProEx Energy Ltd.
Calgary, Alberta

Brian McLachlan ^{(2) (3) (4)}
President & Chief Executive Officer
Yoho Resources Inc.
Calgary, Alberta

Gary E. Perron ^{(1) (2)}
Senior Vice President and
Managing Director
BMO Nesbitt Burns
Calgary, Alberta

Terrance D. Svarich ^{(1) (3) (4)}
President
Devsun Ltd.
Calgary, Alberta

⁽¹⁾ Member of Audit Committee

⁽²⁾ Member of Compensation
Committee

⁽³⁾ Member of Reserve Committee

⁽⁴⁾ Member of Technical Services
Committee

Environment, Health and Safety, Corporate
Governance and Nomination Matters are
addressed by the entire Board of Directors

Officers

David D. Johnson
President and
Chief Executive Officer

Steven A. Allaire
Vice President Finance and
Chief Financial Officer and Corporate
Secretary

Corporate Office

1200, 205 – 5th Avenue S.W.
Calgary, Alberta
T2P 4B9
Telephone: (403) 216-2510
Facsimile: (403) 216-2514
Website: www.proxenergy.com

Bankers

Bank of Montreal
Corporate Banking
Canada Trust Tower
2200, 333 – 7th Avenue S.W.
Calgary, Alberta
T2P 2Z1

Trustee and Transfer Agent

Computershare Trust Company
of Canada
Calgary, Alberta

Stock Exchange

The Toronto Stock Exchange trading
symbol PXE

Solicitor

Burnet, Duckworth & Palmer LLP
1400, 350 – 7th Avenue S.W.
Calgary, Alberta
T2P 3N9

Auditor

KPMG LLP
2700, 205 – 5th Avenue S.W.
Calgary, Alberta
T2P 4B9

Consulting Engineers

GLJ Petroleum Consultants Ltd.
4100, 400 – 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

ProEx Energy Ltd.

2006

Financial Information

ProExEnergy



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Telephone 403-216-2510
Fax 403-216-2514
www.proxenergy.com



During 2006, ProEx more than doubled its reserves through the drilling of 44 net wells. Proved plus probable reserves increased to 31.5 million boe from 15.0 million boe at December 31, 2005, an increase of 110 percent, or 88 percent per share, diluted. Since January 1, 2006, reserves have increased 211 percent, or 758 percent on a per share basis, diluted.

285,000⁺

acres of undeveloped land

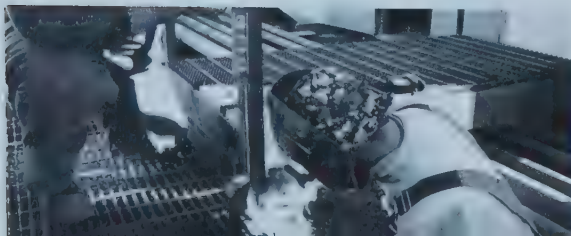
acres

Foothills over the past four years, ProEx has been able to optimize drilling practices and pursue cost savings to help mitigate spiraling industry service costs. Careful capital allocation is also a key contributor to capital efficiency. Since July 2004 the Company has allocated approximately 20 percent of its capital investment to land and seismic, 20 percent to facility construction and 60 percent to drilling and completions. This allocation ratio has provided the necessary capital to generate production and reserve growth as well as add to future growth potential through land and seismic investment. Prospect selection is likely the most important ingredient for a successful and efficient exploration program. Potential reserve target size must be realistic given the cost structure that prevails in the Western Canadian Sedimentary Basin. ProEx has been able to secure a dominant position on a trend that has an above average reserve per well result and is repeatable on trend. The average proved plus probable reserve assignment per successful well drilled since the Company started operations in the Foothills is 2.4 bcfe. In total ProEx has booked almost 200 bcfe to this project area.

Production increased to 6,080 boe per day in the fourth quarter of 2006 from 4,561 boe per day in the fourth quarter of 2005, an increase of 33 percent, or 21 percent on a per share basis, diluted. This production growth, from approximately 950 boe per day in July 2004 to current levels, has been achieved solely through exploration efforts with no acquisitions and represents an increase of 540 percent, or 379 percent on a per share basis, diluted.

During the year the Company significantly increased its undeveloped land position in northeast British Columbia. Total undeveloped land under control was 285,000 acres at December 31, 2006 up from 207,000 acres at December 31, 2005. During the fourth quarter of 2006 the Company acquired a new, on trend, land position to the north, at Caribou and Sikanni where the potential exists for the Triassic Halfway trends to continue, as well as the shallower Cretaceous horizons. These lands together with pre-existing undeveloped lands will provide significant opportunities for 2008 and beyond.

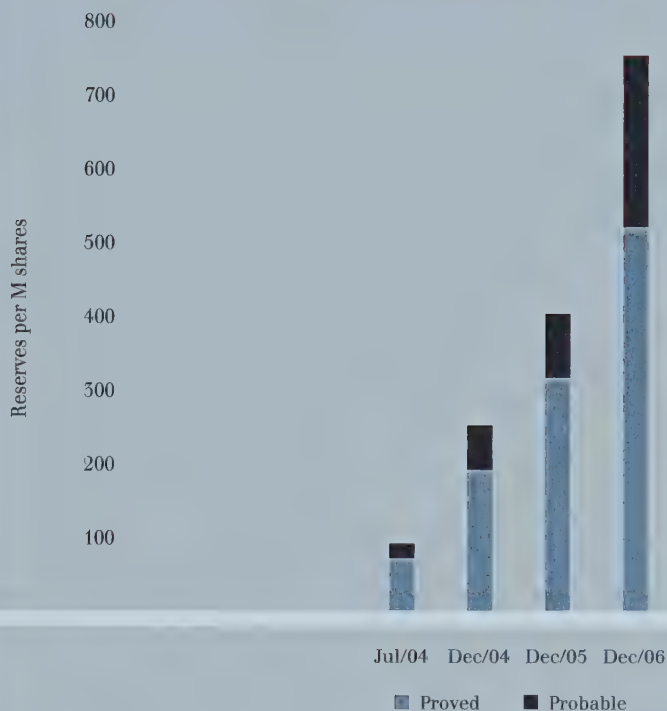
The Company has made a substantial investment in 3-D seismic in its area of operations in the Foothills with over 1,100 square kilometers of 3-D seismic data providing the Company with a significant technical advantage. Seismic coupled with detailed geological mapping has been the key to unlocking this play.



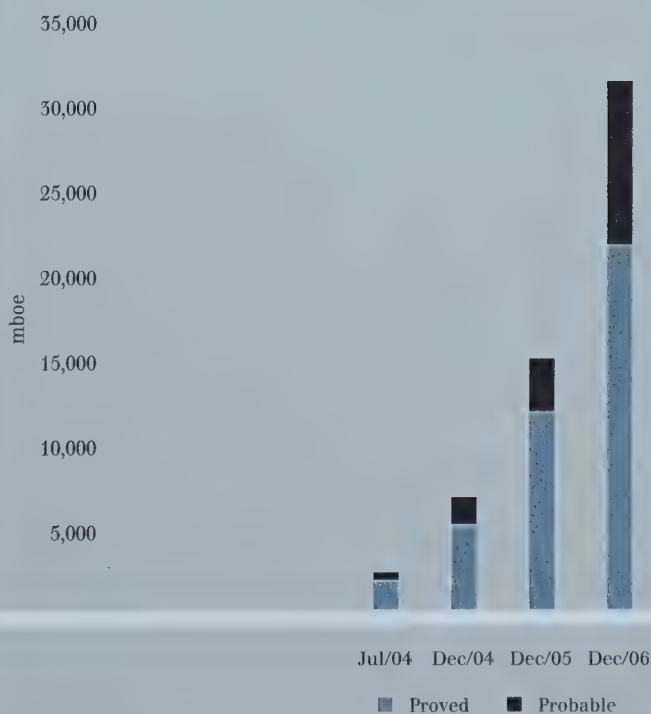
RESERVE GROWTH

During 2006, ProEx more than doubled its reserves through the drilling of 44 net wells. Proved plus probable reserves increased to 31.5 million boe from 15.0 million boe at December 31, 2005, for an increase of 110 percent, or 88 percent per share, diluted. Since July 2004 reserves have increased 1,211 percent, or 758 percent on per share basis, diluted.

RESERVES PER DILUTED SHARE



RESERVES



31.5 million

BOE proved plus probable reserves

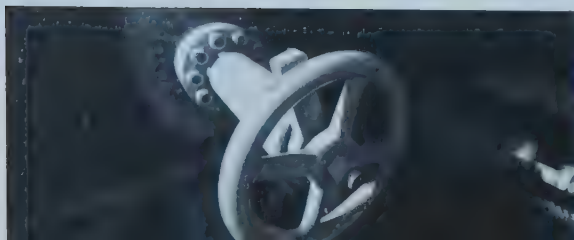
BOE

The Company invested approximately \$152 million during 2006 and drilled a total of 44.0 net wells resulting in 41.0 net gas wells and 1.3 net oil wells for an overall success rate of 96 percent. During 2006, the Company extended the Halfway trend to the north and west with drilling successes at Lily Lake, Sasquatch, Julianne and Dogrib. Follow up drilling in these new exploratory areas continues in the first quarter of 2007. Also to the south the Company continues to build upon its positions at Bernadet and Altares. While the majority of the drilling success during 2006 was in the traditional Halfway reservoirs, the Company enjoyed considerable success in the Cretaceous zones at Gundy, Julianne and West Beg. ProEx has approximately 120 net wells in its drillable inventory with approximately one third of these now being comprised of Cretaceous locations. This inventory represents, at our current pace, approximately three years of inventory. The Cretaceous inventory is entirely new and incremental to the Triassic Halfway project and is a result of successful drilling conducted during 2006.

The Company financed its 2006 program with the proceeds of two equity offerings during the year, cash flow and bank debt. The Company issued 3,000,000 common shares in May at a price of \$16.15 per share and issued 2,000,000 common shares and 1,250,000 flow-through shares in November at a blended price of \$13.88 per share. The Company ended 2005 with net debt of \$27.8 million on a borrowing base of \$100 million.

Production growth offset a 30 percent decline in average natural gas prices delivering cash flow from operations for the year of \$43.5 million compared to \$36.0 million in 2005 and year over year net earnings remained unchanged at approximately \$15.2 million. Natural gas prices averaged \$7.08 per mcf during 2006 compared to \$9.70 per mcf during 2005.

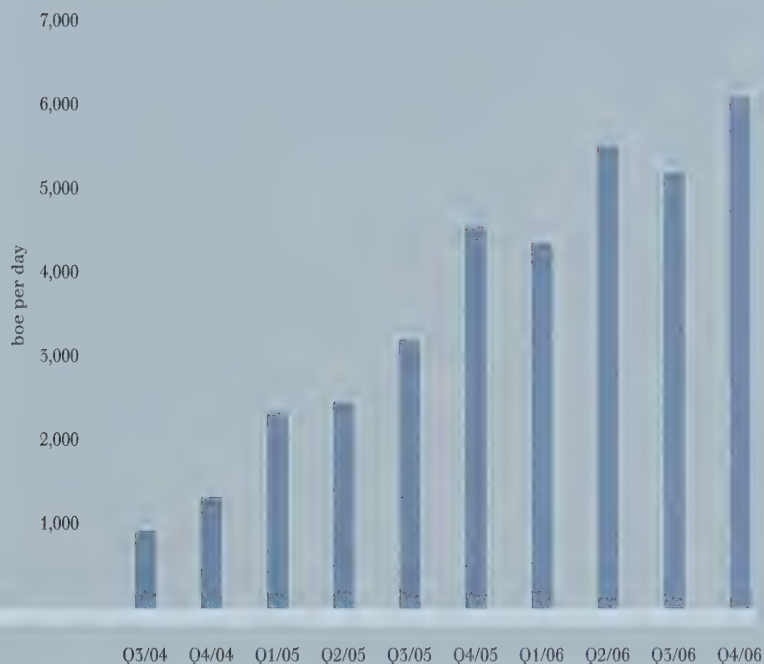
For 2007, the Company has set an initial capital budget which will be funded by cash flow and debt. The equity offer in late 2006 combined with the hedging of approximately one-half of natural gas production through to the end of October 2007 will allow ProEx to continue at an active pace during the year. The potential for weaker natural gas prices exists as a result of the historically high levels of natural gas in storage and record levels of drilling activity in the United States. The Company's balance sheet is well positioned to withstand the potential volatility associated with these circumstances.



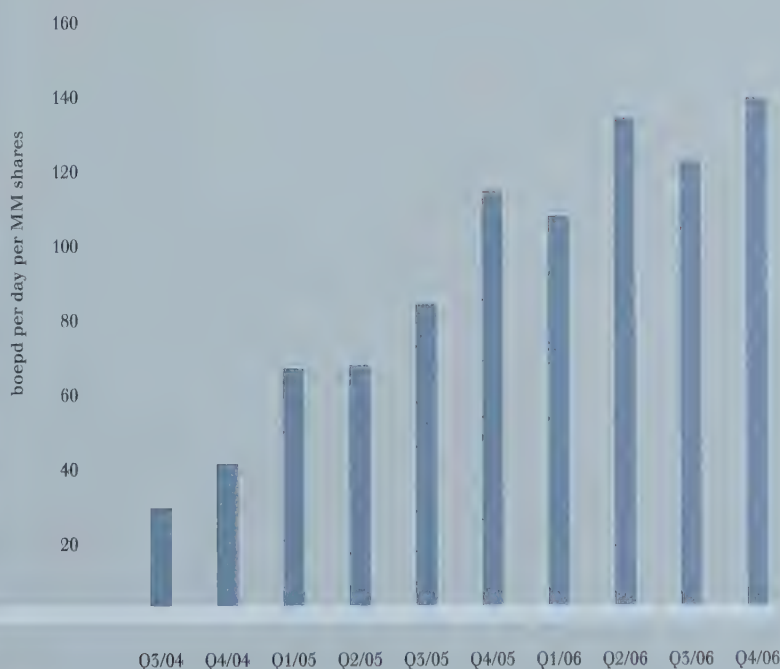
PRODUCTION GROWTH

Production increased to 6,080 boe per day in the fourth quarter of 2006 from 4,561 boe per day in the fourth quarter of 2005, an increase of 33 percent, or 21 percent on a per share basis, diluted. This production growth, from approximately 950 boe per day in July 2004 to current levels has been achieved solely through exploration efforts with no acquisitions and represents an increase of 540 percent, or 379 percent on a per share basis, diluted.

QUARTERLY PRODUCTION GROWTH



PRODUCTION GROWTH PER SHARE



1,211%

proved plus probable reserve growth per diluted share since July 2004

Growth

For 2007 the Company will invest approximately \$120 million in exploration and development activities and plans to drill, similar to last year, approximately 45 net wells primarily in the Foothills. ProEx will continue to concentrate on its traditional Foothills targeted Halfway reservoirs and in addition will build upon the Cretaceous success with further Bluesky and Gething drilling planned at Julianne, Altares, Bernadet, Gundy and West Beg.

Throughout the Company's history, compression and associated facilities have been built on an aggressive schedule. Often facilities and extension drilling have occurred simultaneously following a new pool discovery which has been on trend to prior successes. This has been accomplished due to the level of technical confidence that has been achieved over the past several years in the Foothills. Gundy, West Beg, Bernadet and most recently Dogrib and Julianne are all examples of this strategy. As the Company expands its exploration efforts over a larger geographic area, the requirement to build incremental infrastructure will determine the timing of grass roots production additions. The focus will continue to be the establishment of threshold production volumes together with the planning and logistics required to achieve industry leading on-stream timing.

Annual production for 2007 is expected to average between 8,500 to 9,000 boe per day with an exit range of 9,500 to 10,000 boe per day. The program will be balanced between exploitation of pools previously discovered and new exploratory initiatives in the Foothills of northeastern British Columbia. Several grass root facility projects and expansions are contemplated following successful drilling results. ProEx has the necessary equipment on order for deliveries throughout the year. The geophysical data base will be expanded with the shooting of one new 3-D survey in the Julianne area in the first quarter and another larger program planned to commence during the fourth quarter to evaluate some of the new lands purchased late in 2006.

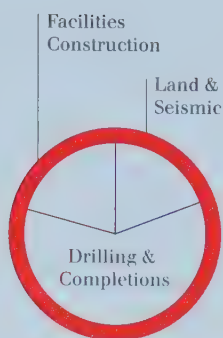
The Company will continue to focus on traditional efficiency measures targeting finding, development and net acquisition costs in the \$10 to \$12 per boe range on a proved plus probable basis and targeting production on-stream costs under \$20,000 per boe per day. ProEx has been able to achieve excellent levels of efficiencies due the quality of the assets combined with the knowledge, skill and creativity of its staff. The Company is focused on the creation of value through the full exploration and development cycle and will continue to measure success in terms of per share value gain.



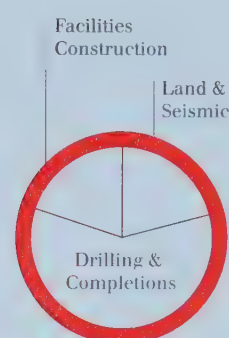
CAPITAL ALLOCATION

Careful capital allocation is also a key contributor to capital efficiency. Since July 2004 the Company has allocated approximately 20 percent of its capital investment to land and seismic, 20 percent to facility construction and 60 percent to drilling and completions.

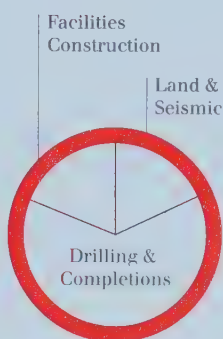
This allocation ratio has provided the necessary capital to generate production and reserve growth as well as add to future growth potential through land and seismic investment.



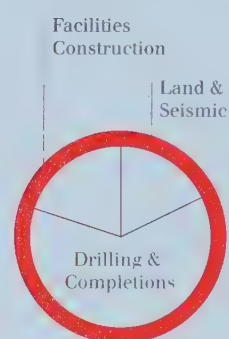
2004 Capital Allocation



2005 Capital Allocation



2006 Capital Allocation



2007 Budgeted Capital Allocation

SHARE PRICE PERFORMANCE

ProEx's share price closed the year at \$12.85, down 22 percent in 2006, consistent with the share price declines experienced across the oil and gas sector. The drop was largely attributable to the steady decline in natural gas prices throughout the year as well as the general industry impact of the trust taxation announcement by the Canadian government on October 31, 2006.

June 30,
2004 = 100



540%

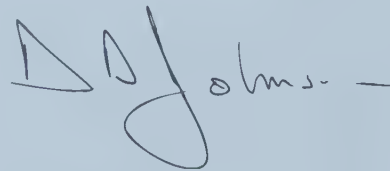
production growth per share diluted since July 2004

since 2004

ProEx's low cost structure and financial strength have positioned the Company to take a consistent approach to natural gas exploration. This approach takes advantage of the substantial momentum that the Company has established over the last 2 ½ years. The Company expects to maintain its pace of drilling activities, and where opportunities present themselves, expand its Foothills presence. ProEx is well positioned to continue its growth profile through 2007 and 2008.

On March 5, 2007 the "Company announced that it had entered into an agreement to acquire certain interests in northeast British Columbia Foothills assets. The Acquisition has an effective date of April 1, 2007 and is expected to close on or about April 2, 2007, with the closing being subject to customary industry conditions. ProEx's total consideration under the agreement is approximately \$134.3 million, subject to certain closing adjustments, and will be financed through a concurrently announced equity offering as well as increased available credit facilities.

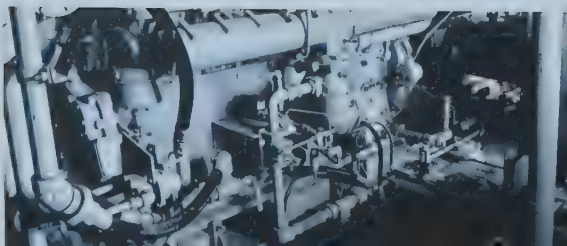
The Acquisition is a unique high-quality opportunity at this time in the cycle and is an extremely complementary fit to ProEx's existing operations in the British Columbia Foothills. The Acquisition includes producing assets with significant exploitation potential and exploratory lands on-trend to the Company's existing Foothills activity. Since inception, the Company's focus has been on building the underlying value of each share of ProEx and to this point this has been accomplished entirely through the drill bit. The assets being acquired are a hand-in-glove fit with our existing producing assets in northeast British Columbia and will expand our exploration inventory and growth potential substantially.



David D. Johnson

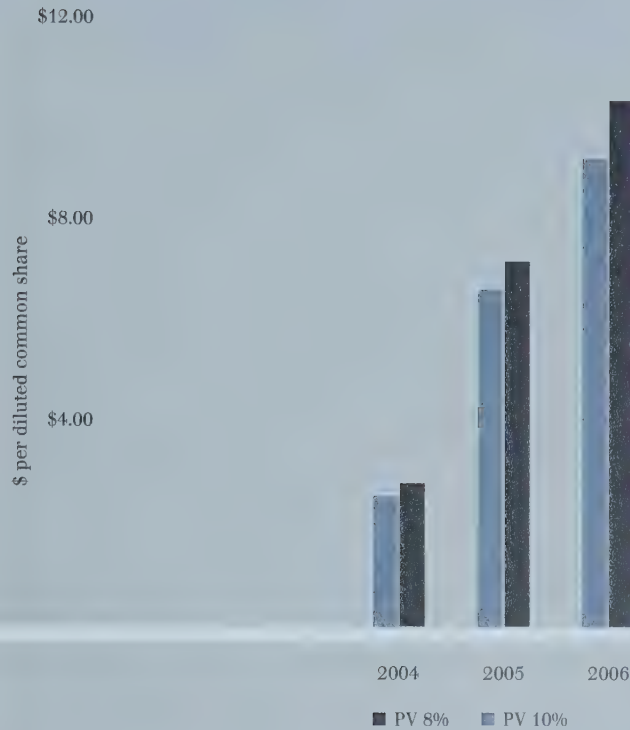
President and Chief Executive Officer

March 5, 2007



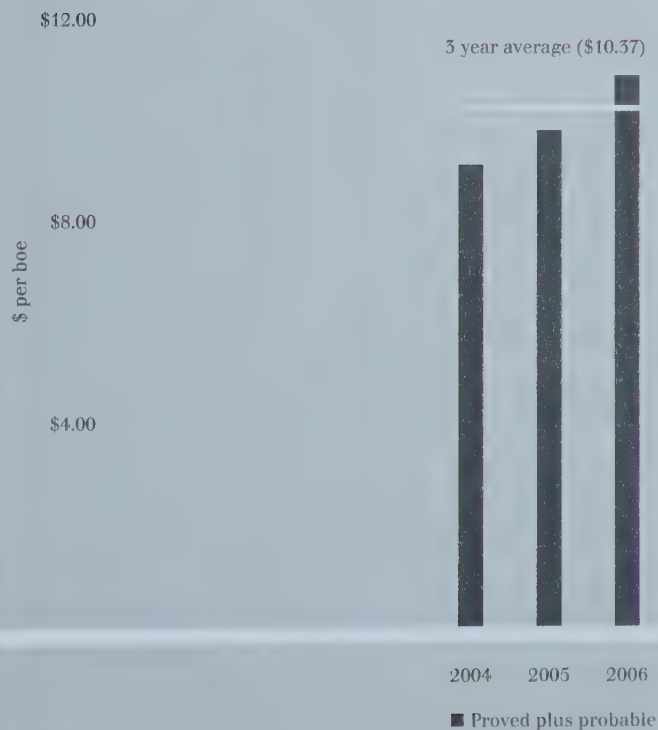
NET ASSET VALUE

(per diluted share-forecast price)



FINDING, DEVELOPMENT & NET ACQUISITION COSTS

(Proved Plus Probable)



FINDING, DEVELOPMENT & ACQUISITION COSTS

For 2006, all-in finding, development and acquisition costs inclusive of changed in future capital were \$10.93 per boe on a proven plus probable basis compared to \$9.85 per boe on a proven plus probable basis in 2005.

The all-in cumulative finding, development and acquisition costs inclusive of changes in future capital since July 2004 are \$10.37 per boe on a proved plus probable basis.

Operations

Northeast British Columbia

ProEx had a successful 2006 concentrating exploration and production efforts almost entirely in the Foothills of northeast British Columbia. Since the inception of the company in 2004 continued advancements in our understanding of the nature of the gas reservoirs in the Foothills have convinced us to accelerate our control of opportunities in this area. To this end ProEx increased its undeveloped land holdings in the Foothills by 52 percent bringing its undeveloped inventory to over 260,000 acres. Virtually all of these lands have been acquired in large contiguous blocks on trend with existing producing fields that ProEx and large competitors have discovered. In the winter of 2006 ProEx recorded its largest 3-D shoot at Sasquatch covering controlled land blocks on trend with West Beg and Town. This 280 square kilometer 3-D program was key in positioning ProEx's new discoveries at Lily and Sasquatch. In addition, a number of undrilled controlled look-alike features of varying sizes exist as drilling inventory for the future.

In 2006 ProEx drilled 63 wells (43.8 net) in northeast British Columbia utilizing a fleet of three to five drilling rigs throughout the drilling season. Successful new Triassic discoveries were made at Dogrib, Sasquatch, Julianne and Lily Lake. These tests have been production tested at commercial rates consistent with our historical norms. Production from these wells, other than Lily Lake, which is significantly removed from existing infrastructure, is expected to commence by the end of the first quarter of 2007. In addition, ProEx, largely with the aid of detailed 3-D seismic reprocessing, made substantial discoveries at Town South, West Beg and Altares in the shallower Cretaceous sands. Recognition of this opportunity combined with our continued deeper exploration will provide ProEx with an expansive and varied inventory over upcoming drilling seasons.



BRITISH COLUMBIA

ProEx's growth efforts are focused in the British Columbia Foothills where it has built an exceptional land position, spanning 140 kilometers in length.

Fort St. John Plains

Foothills



For 2007, ProEx has planned a similar drilling pace as experienced in 2006. The first quarter program will be concentrated at; Altares, a mixed exploration and development Bluesky program with a deep exploratory Doig test; Sasquatch and Dogrib, Halfway drilling stepping out from exploratory successes; Julienne, pushing out the limits of a mixed Halfway and Gething pool; Lily Lake, a Halfway step-out to the fourth quarter discovery and West Beg, accelerating Bluesky/Gething drilling opportunities. On the seismic front, ProEx has contracted to acquire a further 140 square kilometers of 3-D data in the western portion of our controlled land blocks. In addition a reconnaissance 2-D program was conducted with the intention of evaluating opportunities offsetting our Altares pool. For the fourth quarter ProEx has begun the regulatory process enabling the company to proceed on acquiring 3-D data in the newly acquired Caribou-Sikanni area. This shoot is designed to be very extensive overlaying with our 1000 + square kilometers of existing data to the south.

During 2006, following drilling successes the Company constructed new facilities at Dogrib and Julienne and expanded facilities at West Beg, Gundy, Bernadet and Altares. The Company has six operated compression and dehydration facilities in the Foothills. In early February 2007, the Company completed the final portion of the Julienne sales line to the Spectra Energy (formerly Duke) tie in point to by-pass a third party facility that had proved to be unreliable. In addition for 2007, a new facility is planned for Sasquatch/Dogrib and facility expansion is planned at Altares. Other facility construction and expansions will be driven by exploration success.

The Fort St. John Plains region will continue to be a core holding. ProEx participates with its partner, Progress Energy Trust, in their development program with the objective of maintaining production in the range of 750 boe per day. The region remains a high netback area and generates cash flow which is re-invested in long life Foothills opportunities.



Reserves

Summary Reserve Information

ProEx Energy Ltd. for the year ended two thousand and six

ProEx's reserves were prepared by the independent engineering firm of GLJ Petroleum Consultants ("GLJ"). Reserves included herein are stated on a company interest basis (before royalty burdens and including royalty interests) unless noted otherwise. All reserves information has been prepared in accordance with National Instrument ("NI") 51-101.

Summary of Reserves *(forecast prices)*

	2006	2005
Proved		
Light and medium oil <i>(mbbls)</i>	508	500
Gas <i>(mmcf)</i>	119,969	64,436
NGL <i>(mbbls)</i>	1,165	532
BOE <i>(mboe)</i>	21,668	11,771
Proved plus probable		
Light and medium oil <i>(mbbls)</i>	759	651
Gas <i>(mmcf)</i>	173,737	82,141
NGL <i>(mbbls)</i>	1,798	683
BOE <i>(mboe)</i>	31,513	15,024

Total proved reserves at December 31, 2006 increased 84 percent to 21.7 million boe compared to 11.8 million boe in 2005. Total proved plus probable reserves at December 31, 2006 increased 110 percent to 31.5 million boe compared to 15.0 million boe in 2005. Reserve growth in 2006 was achieved through the drill bit and replaced 955% percent of production on a proved plus probable basis and 613% percent on a proved basis.

The Company's actual natural gas and petroleum reserves and future production will be greater than or less than the estimates provided. The estimated future net revenue from the production of the Company's natural gas and petroleum reserves does not represent the fair market value of the Company's reserves. In addition to the summary reserve information disclosed in this annual report, more detailed reserve disclosure in accordance with NI 51-101 is included in the Company's Annual Information Form ("AIF"). A copy of the Company's AIF can be obtained by contacting the Company or visiting its website www.proxenergy.com or through SEDAR at www.sedar.com.

Summary Reserve Information

ProEx Energy Ltd. for the year ended two thousand and six

2006 Summary of Oil and Gas Reserves *Forecast Prices and Costs, Company Interest*

	Light and Medium Crude Oil	Natural Gas Liquids	Natural Gas	Total 2006	Total 2005
	(mbbls)	(mbbls)	(bcf)	(mboe)	(mboe)
Proved					
Developed producing	413	772	87.5	15,762	8,402
Developed non-producing	61	129	9.7	1,808	1,441
Undeveloped	33	264	22.8	4,093	1,927
Total proved	507	1,165	119.9	21,663	11,771
Probable	251	632	53.8	9,843	3,254
Total proved plus probable	757	1,798	173.7	31,507	15,024

Note: May not add due to rounding

Net Present Value of Reserves, Forecasted Prices and Costs

(\$ thousands)	Undiscounted	Discounted at 5%	Discounted at 8%	Discounted at 10%
Proved				
Developed producing	453,872	308,273	259,940	236,060
Developed non-producing	51,982	30,764	24,549	21,652
Undeveloped	65,647	38,434	27,959	22,506
Total proved	581,501	377,471	312,448	280,218
Probable	327,055	151,980	108,069	89,137
Total proved plus probable	898,557	529,451	420,517	369,355

Note: May not add due to rounding

2.4^{Bcfe} Reserves

average proved plus probable reserve assigned per successful well since July 2004

Reconciliation of Company Interest Reserves by Principal Product Type

Forecast Prices and Costs

		Light and Medium Crude	Natural Gas	Natural Gas Liquids	BOE
		(mbbls)	(bcf)	(mbbls)	(mboe)
Total Proved	Opening balance	500.1	64.45	531.9	11,773.4
	Exploration discoveries	—	1.97	75.9	343.6
	Drilling extensions	8.7	57.51	747.1	12,007.3
	Infill Drilling	—	0.46	7.1	83.3
	Improved recovery	—	—	—	—
	Technical revisions	121.1	(3.89)	(84.2)	(610.8)
	Economic factors	—	—	—	—
	Acquisitions	—	—	—	—
	Dispositions	—	—	—	—
	Production	(122.3)	(10.53)	(52.6)	(1,929.0)
	Closing balance	507.7	119.97	1,165.4	21,667.9
Probable	Opening balance	151.5	17.71	151.4	3,254.2
	Exploration discoveries	—	0.98	8.0	171.8
	Drilling extensions	98.0	36.56	486.6	6,678.0
	Infill Drilling	—	0.35	5.7	63.7
	Improved recovery	—	—	—	—
	Technical revisions	1.6	(1.89)	(20.0)	(334.3)
	Economic factors	—	—	—	—
	Acquisitions	—	0.06	1.0	11.5
	Dispositions	—	—	—	—
	Production	—	—	—	—
	Closing balance	251.0	53.77	632.5	9,844.8
Proved Plus Probable	Opening balance	651.6	82.16	683.3	15,027.6
	Exploration discoveries	—	2.95	23.9	515.4
	Drilling extensions	106.7	104.07	1,233.7	18,685.3
	Infill Drilling	—	0.81	12.8	147.0
	Improved recovery	—	—	—	—
	Technical revisions	122.7	(5.78)	(104.2)	(945.1)
	Economic factors	—	—	—	—
	Acquisitions	—	0.06	1.0	11.5
	Dispositions	—	—	—	—
	Production	(122.3)	(10.53)	(52.6)	(1,929.0)
	Closing balance	758.7	173.74	1,797.9	31,512.7

Shareholder Information

ProEx Energy Ltd.

Annual Meeting

The Annual General Meeting of Shareholders will be held on Tuesday, April 24, 2007 at 3:30 p.m. in the McMurray Room, Calgary Petroleum Club, Calgary, Alberta.

Annual Information Form

Copies of the Annual Information Form are available to shareholders upon request, on our website or at www.sedar.com.

www.proxenergy.com

Shareholders and interested investors are encouraged to visit our web site. Historical public disclosure documents (in PDF format), latest presentation material, press releases are all available. Filings also available at: www.sedar.com

Transfer Agent

Computershare Trust Company of Canada
Suite 600, 530 – 8th Avenue S.W.
Calgary, Alberta T2P 3S8
Toll Free: 1-888-267-6555

Investor Relations

Steven A. Allaire
Vice President Finance & CFO
Telephone: (403) 216-2510
Facsimile: (403) 216-2514
Email: ir@proxenergy.com

Corporate Governance

A system of corporate governance for the Corporation has been established to provide the Board of Directors, management and shareholders of the Corporation with effective governance. A more detailed discussion of corporate governance is available in the Information Circular for the Annual General Meeting of Shareholders.

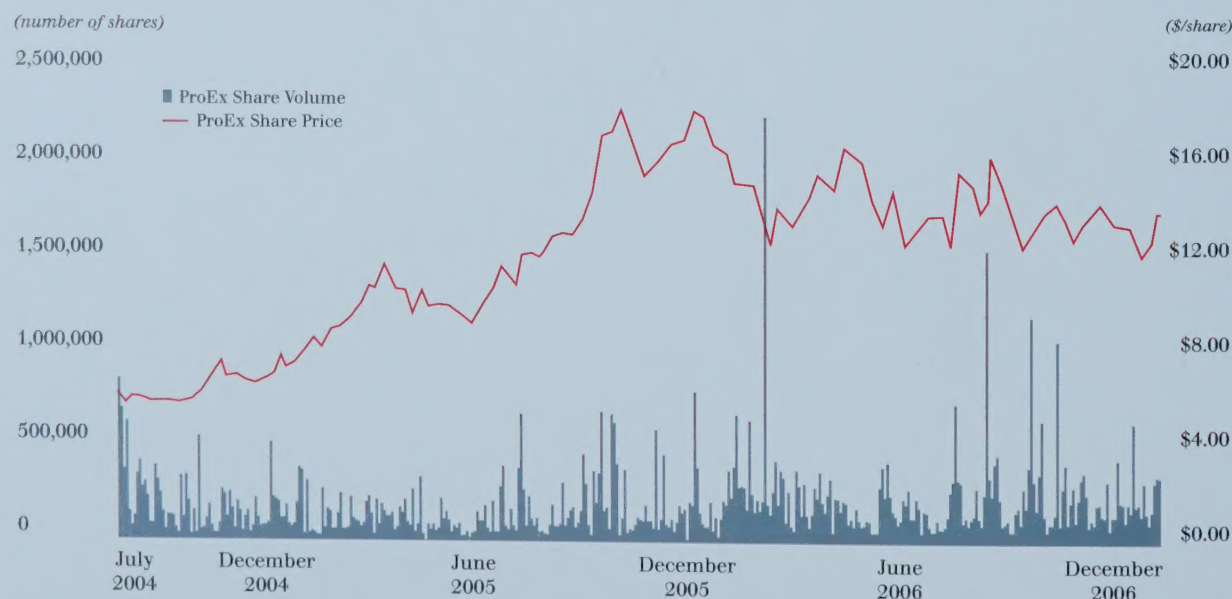
Stock Exchange Listings

The Toronto Stock Exchange Symbol: PXE

Estimated Release Date of Quarterly Results

First Quarter April 23, 2007
Second Quarter July 24, 2007
Third Quarter October 23, 2007

Share Volume and Share Price (July 7, 2004 to February 26, 2007)



Corporate Information

ProEx Energy Ltd.

Directors

John M. Stewart ⁽¹⁾⁽⁴⁾

Chairman

ProEx Energy Ltd.

Vice Chairman

ARC Financial Corporation

Scottsdale, Arizona, USA

David D. Johnson

President &

Chief Executive Officer

ProEx Energy Ltd.

Calgary, Alberta

Brian McLachlan ⁽²⁾⁽⁵⁾⁽⁴⁾

President &

Chief Executive Officer

Yoho Resources Inc.

Calgary, Alberta

Gary E. Perron ⁽¹⁾⁽²⁾

Senior Vice President and

Managing Director

BMO Nesbitt Burns

Calgary, Alberta

Terrance D. Svarich ⁽¹⁾⁽⁵⁾⁽⁴⁾

President

Devsun Ltd.

Calgary, Alberta

Officers

David D. Johnson

President &

Chief Executive Officer

Steven A. Allaire

Vice President Finance &

Chief Financial Officer &

Corporate Secretary

Corporate Office

1200, 205 – 5th Avenue S.W.

Calgary, Alberta T2P 4B9

Telephone: (403) 216-2510

Facsimile: (403) 216-2514

Website: www.proexenergy.com

Bankers

Bank of Montreal

Corporate Banking

2200, 333 – 7th Avenue SW

Calgary, Alberta T2P 2Z1

Solicitor

Burnet, Duckworth & Palmer

1400, 350 – 7th Avenue S.W.

Calgary, Alberta T2P 3N9

Auditor

KPMG LLP

2700, 205 – 5th Avenue SW

Calgary, Alberta T2P 4B9

Consulting Engineer

GLJ Petroleum Consultants

4100, 400 – 3rd Avenue S.W.

Calgary, Alberta T2P 4H2

⁽¹⁾ Member of Audit Committee

⁽²⁾ Member of Compensation Committee

⁽³⁾ Member of Reserve Committee

⁽⁴⁾ Member of Technical Services Committee

ProEx Energy Ltd.

2006
Performance Report

ProExEnergy



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